Permit Application
Additional Furnace Project

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Project No. 412-15

February 2012

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Section 1 | Introduction

INEOS USA LLC (INEOS) operates an existing olefins manufacturing facility (No. 2 Olefins Unit) in Alvin, Brazoria County, Texas under Permit No. 95-PSD-TX-854 and various permits by rule. INEOS is submitting this application to authorize the installation and operation of an additional cracking furnace at the No. 2 Olefins Unit in accordance with Title 30 Texas Administrative Code (TAC) Chapter 116 and 40 CFR 52.

1.1 Purpose of Application

The INEOS Chocolate Bayou Plant is submitting this permit application in accordance with TCEQ Chapter 116 to authorize the installation and operation of a new cracking furnace, decoking drum and associated equipment. There will be no effect on the emissions from existing operations (No. 2 Olefins Unit) associated with this application. The purpose of the project is to allow an increase in capacity by ensuring that unit rates are maximized during periods when a furnace is off-line for decoking. Because the furnace is new, it will have increased yield, increased energy efficiency and lower NO_X emissions than the existing furnaces. (The energy efficiency of the new furnace is discussed in more detail in Section 5.3 of the permit application.) INEOS expects to increase ethylene capacity by approximately 150 million pounds per year.

Specifically, the new proposed facilities will primarily consist of one cracking furnace, a new decoke cyclone/stack (dedicated to the new furnace), and fugitive emissions components. The new furnace will be rated at 495 MMBtu/hr (HHV) to produce ethylene. The furnace will be equipped with an ammonia selective catalytic reduction system (SCR) to reduce NO_X emissions. Since INEOS is still in the vendor selection phase of this project, the most likely operating scenario is being represented for permitting purposes. However, INEOS is committed to meet the emission limitations and control measures represented in this application.

INEOS is currently conducting an Air Quality Analysis (AQA) for the Project to demonstrate that the proposed Plant off-site contaminant impacts will be in compliance with state and federal requirements. The PSD AQA Report will be submitted as a separate stand-alone document subsequent to the submittal of this PSD air permit application.

1.2 NA/PSD Applicability

Because INEOS is proposing the installation of new facilities at a major source, the project has been reviewed for potential applicability for Nonattainment New Source Review (NA) and Prevention of Significant Deterioration Review (PSD). The project is considered a major modification. Pollutants associated with this project include greenhouse gases (GHG), carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM, PM_{10}, and $PM_{2.5}$), sulfur dioxide (SO_2), ammonia (NH_3) and volatile organic compounds (VOC). The greenhouse gases are calculated carbon dioxide equivalent CO_2e.

INEOS Chocolate Bayou is located in Brazoria County, which is designated as severe Nonattainment for ozone. This designation is based on the 8-hour ozone (1997) standards. VOC and NO_X are identified as precursors for ozone. Projects with an increase (not taking into account decreases) of 5 tpy of NO_X and/or VOC must undergo NA review. The VOC and NO_X emissions associated with this project have an increase of greater than 5 tpy of VOC and NO_X, therefore contemporaneous netting was performed. The contemporaneous period is defined as five years before the start of construction to the start of operation. The nonattainment net change in emissions in the contemporaneous period are less than 25 tpy, therefore nonattainment permitting is not required for this project. Detailed netting tables are included in Appendix C.

PSD regulations apply to the following criteria pollutants: NO_X, SO_2, CO, PM, PM_{10} and $PM_{2.5}$. A summary of PSD requirements are outlined in Table 1-1. As demonstrated, this project will trigger PSD permitting for PM_{10} and $PM_{2.5}$.

Table 1-1| Emission Summary for PSD Federal Review

Pollutant	Proposed Emission (tons)	PSD Threshold (tons)	Is Project Netting Required?	Is PSD Permitting Required
NO_X	21.68	40	Yes	No
SO_2	1.49	40	No	No
CO_2e	216,779	75,000	Yes	Yes
CO	97.88	100	No	No
PM	13.07	25	No	No
PM_{10}	10.32	15	No	No
$PM_{2.5}$	5.88	10	No	No

Beginning on January 2, 2011, GHGs are a regulated NSR pollutant under the PSD major source permitting program when they are emitted by new sources or modifications in amounts that meet the Tailoring Rule's set of applicability thresholds, which phase in over time. For PSD purposes, GHGs are a single air pollutant defined as the aggregate group of the following gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), and hydrofluorocarbons (HFCs). For GHGs, the Tailoring Rule does not change the basic PSD applicability process for evaluating whether there is a new major source or modification. The applicability threshold for the source is based on CO_2 equivalent (CO_2e) emissions as well as its GHG mass emissions. Permits issued (and associated construction commenced) after July 1, 2011 and before June 30, 2013 fall into Step 2 of this rule. Therefore, PSD permitting requirements will for the first time apply to new construction projects that emit GHG (CO_2e) emissions of at least 100,000 tpy and modification to existing sources with emissions greater than 75,000 tpy even if they do not exceed the permitting thresholds for any other pollutant. In December 2010, EPA finalized a rule that designates EPA as the permitting authority for GHG emitting sources in Texas. This rule is in effect until the EPA approves a SIP that allows Texas to regulate GHG.

Because CO_2e emissions associated with the proposed project are above significance levels, INEOS is submitting a copy of this application to EPA.

1.3 TCEQ Forms and Information

TCEQ forms for the new proposed facilities are listed below and provided in Appendix A. These include the following TCEQ Forms:

Form PI-1	General Application for Air Preconstruction Permit and Amendments
Table 1(a)	Emission Sources
Table 2	Material Balance
Table 30	Estimated Capital Cost and Fee Verification

1.4 Site Description

The INEOS Chocolate Bayou Plant is located in Brazoria County, which is classified as a severe non-attainment area for ozone. Figure 1-1 is an area map showing the location of the Chocolate Bayou Plant and the surrounding area. This figure includes a 3,000-foot radius circle and a 1-mile radius circle. As shown, there are no schools within 3,000 feet of the Chocolate Bayou Plant. Figure 1-2 is a plot plan showing plant boundaries in relation to geographical features such as highways, roads, streams, lakes, and significant facilities not owned or operated by INEOS.

1.5 Upstream/Downstream Analysis

The addition of a new cracking furnace and associated equipment is not expected to result in any emissions increase in any upstream or downstream facilities.

The effluent from the new furnaces will be processed in the No. 2 Olefins unit. No additional energy is needed to process the feed, except for steam used to drive various process and refrigeration compressors. This steam is generated by recovered heat from the cracking process, and the steam produced by the proposed furnace will be sufficient to cover any increased energy needs. INEOS projects that, due to the higher efficiency of the proposed furnace, supplemental steam demand from boilers at the site (authorized by TCEQ Permit No. 2798) and actual emissions will decrease.

All process vents in the No. 2 Olefins unit are recycled to another portion of the process, so there will be no increase in routine venting to the flare.

Other than fugitive emissions points directly involved in the proposed furnace, which are included in the application, there will be no increase in components elsewhere in the unit. Some changes to distillation tower internals (i.e., trays, etc.) may be necessary to accommodate the additional process rates, but these will not involve any emissions increases.

The primary products from the No. 2 Olefins unit (ethylene and propylene) are transported via pipeline, so there are no impacts on storage or loading emissions.

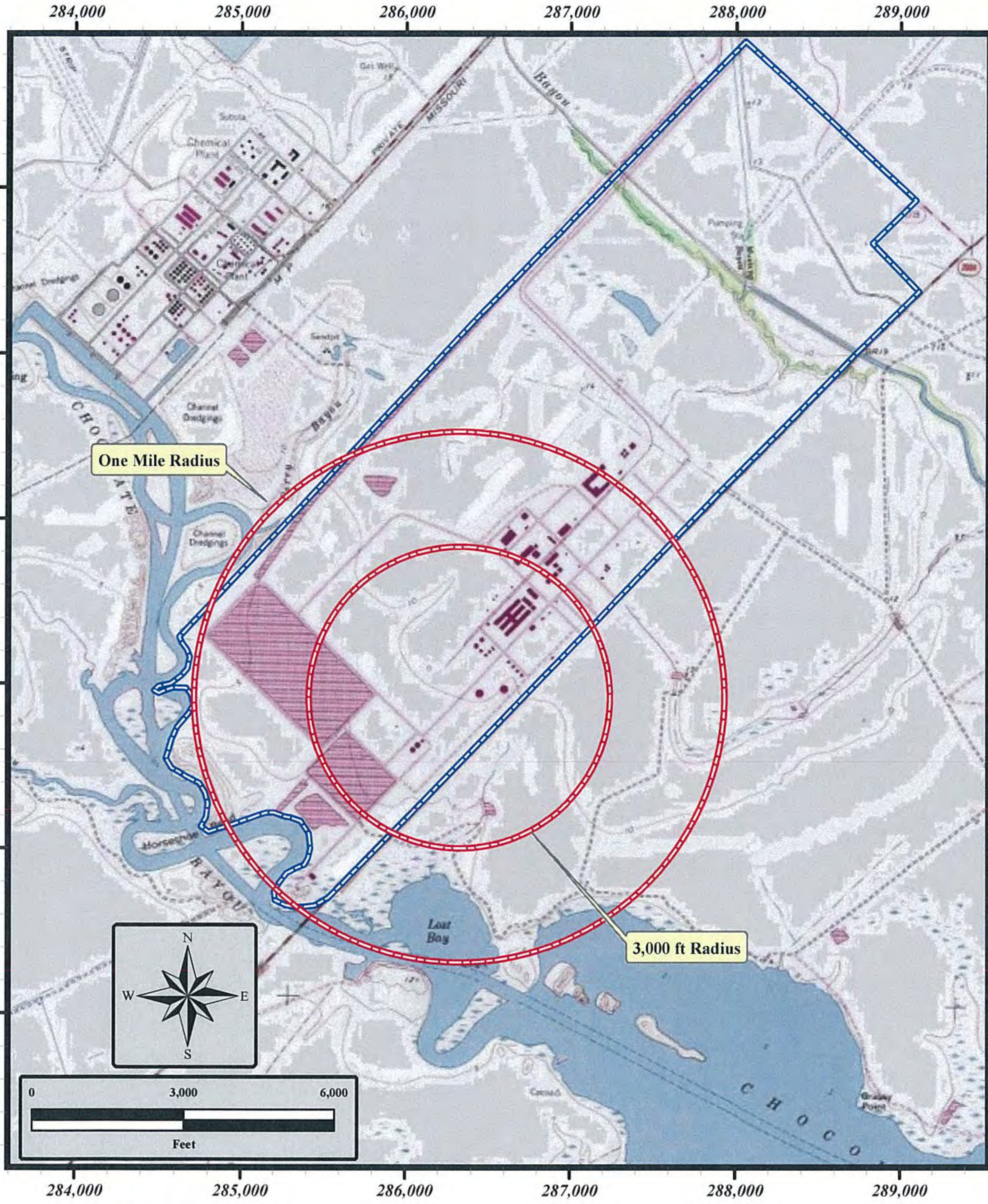
1.6 Permit Fee

Pursuant to § 116.141(a), the permit application fee is calculated based on the estimated capital cost of the project. The permit fee is calculated in Table 30. A check for the application fee has been submitted to the TCEQ Revenue Section under separate cover. Because the capital cost associated with the project is greater than $2 million, a Professional Engineer (PE) signature is required. The Table 30, PE signature and a copy of the check can be found in Appendix A.

1.7 Public Notice

Air quality permit applications are required to comply with the Public Notice (PN) requirements of Title 30 TAC Chapter 39, Subchapters H and K. PN is required for permit amendments if the total net emission increases exceed the public notice de minimis levels in 30 TAC Chapter 39, Subchapter H. New emission increases are defined as the sum of the allowable emission increases and the allowable emission decreases for each air contaminant affected by the amendment application, per the TCEQ Draft *Guidance Document for Public Notice Procedures for New Source Review Air Quality Permit Applications*, dated October 25, 2001. There are no proposed project decreases associated with this project so the project emission increases are evaluated for public notice. Because these are new sources, net emission increases were not calculated. The emission increases associated with this project will require PN. Please refer to Appendix C for more detail.

Figure 1-1 | Area Map



Grid Presended is UTM Zone 15, NAD 1927

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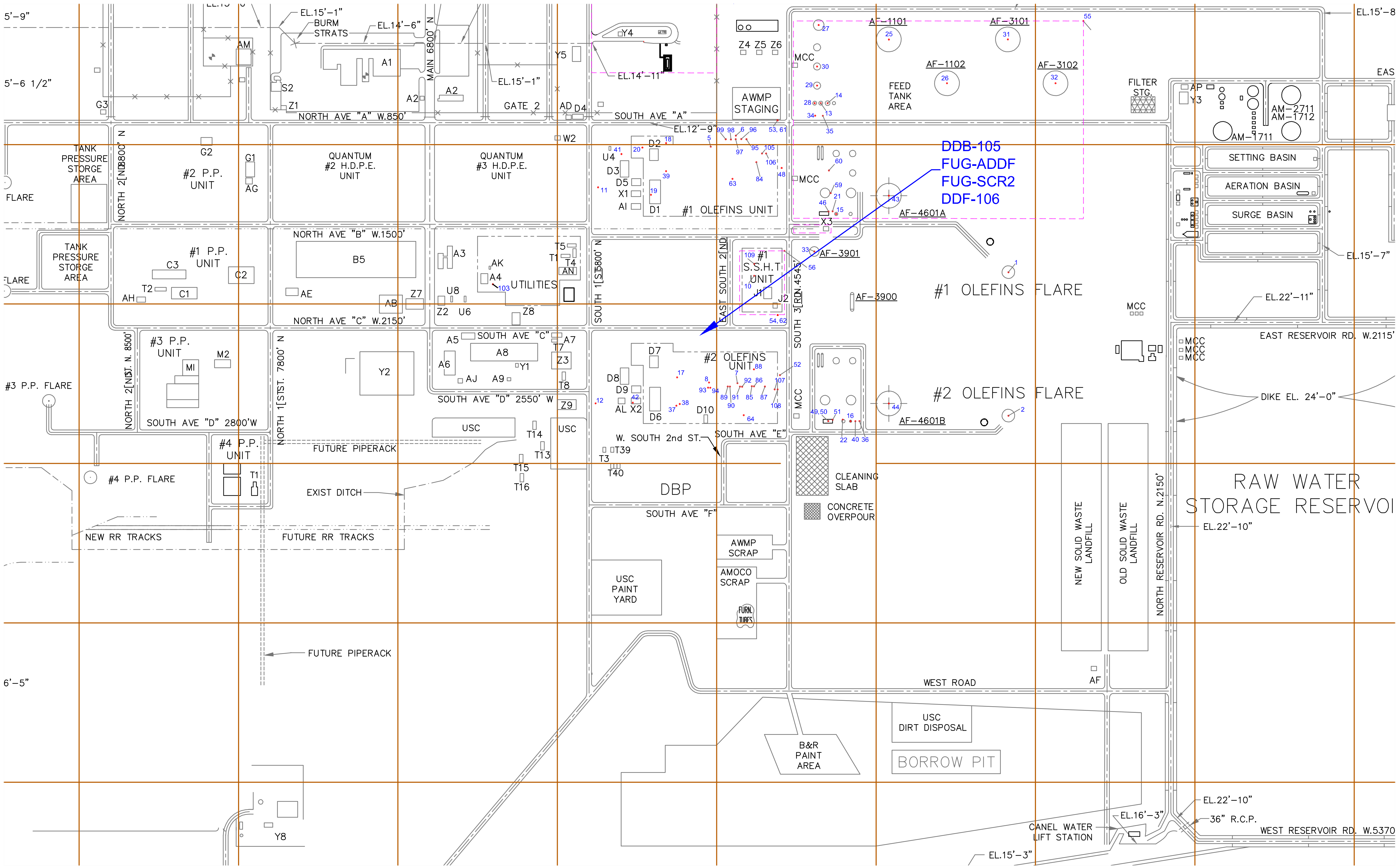
FIGURE 1-1 AREA MAP

INEOS USA LLC
Chocolate Bayou Plant
July 2011
TITAN Project No. 412-15
from USGS Quadrangles
Mustang Bayou & Hoskins Mound, Texas
Date Maps Published 1977
Digital Data Courtesy of ESRI Online Datasets

Figure 1-2 | Plot Plan

EPN	Description	Easting	Northing
DDB-105	Furnace No. 105	286,473.18	3,235,408.88
FUG-ADDF	Furnace No. 105 VOC Fugitives	286,473.18	3,235,408.88
FUG-SCR2	Furnace No. 105 Ammonia Fugitives	286,473.18	3,235,408.88
DDF-106	Furnace No. 105 Decoke Cyclone	286,473.18	3,235,408.88



NOTES

Map provided by RMT

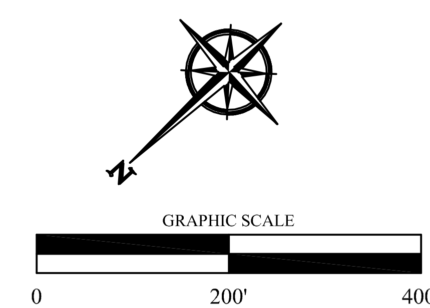


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FIGURE 1-2
PLOT PLAN

INEOS USA LLC
Chocolate Bayou Plant

DESIGNED BY:	DETAILED BY:	CHECKED BY:
RMT	TEI	AL

FILE NAME: T:\INEOS/412-15 Olefins No. 2 Furnace\Figures

DATE:	PROJECT NO.:	PLOT SCALE:
07/2011	412-15	1"=200'
DRAWING NO.:	REVISION:	FIGURE:
TEI-0000	0	1-2

Section 2 | Process Description

2.1 Feed Preparation/Cracking Furnaces

All feedstocks arrive via pipeline to the No. 2 Olefins Unit. The feedstocks may be liquid (e.g., raffinate, naphtha, and debutanized natural gasoline (DNG), or any combination thereof) or gas (ethane-propane mixtures in varying compositions). The feed may also be a mixture of such gas and liquid feeds. All feedstocks must be prepared prior to passing through the cracking furnaces. The gas feedstocks must be dried and vaporized prior to cracking. The liquid feedstocks must be preheated. The feed vaporization and preheat, along with all other heat exchange in the process, is done in closed systems (with the exception of the atmospheric cooling tower).

The new furnace will be an addition to the ten existing cracking furnaces for the No. 2 Olefins Unit. The cracking process is used to convert saturated (paraffinic) hydrocarbons into lower molecular weight unsaturated (olefinic) hydrocarbons which are useful as industrial raw materials.

A cracking furnace has two main sections; the radiant section and the convection section.

The radiant section consists of a number of tubes passing through a large cabin-like firebox with burners mounted on the floor and/or walls. The burners are fueled by a mixture of natural gas and hydrogen. The tubes carry feedstock mixed with steam through the firebox, where heat generated by the burners cracks the feedstock, producing lower molecular weight hydrocarbons, including olefins. A byproduct of this cracking is coke, which is gradually deposited on the inner walls of the furnace tubes. Periodically, the feed flow through the tubes is suspended and the layer of coke is removed in a decoking step as described in Section 2.1.1)

In the convection section, the hot flue gas generated within the firebox is used to heat furnace inlets and to generate high-pressure steam to be used elsewhere in the plant. The convection section therefore serves to recover useful heat from the cracking process.

2.1.1 Decoking

Periodically the furnace must be decoked to remove the accumulation of coke from the inside of the furnace tubes. During this step, all hydrocarbon feed to the furnace is cut off, leaving steam as the sole stream in the feed tubes and the fuel firing rate is reduced. In the initial phase, steam introduced to the tubes purges all hydrocarbons to the cracked gas header. Following this purge, the cracked gas header is closed and the furnace tube outlet is lined up to the decoke header, thereby releasing water vapor to the atmosphere. At this time, air is fed to the tubes, creating a controlled combustion that burns the coke from the tube walls. The gasses (CO_2, nitrogen, water vapor and CO) resulting from this combustion and particulate matter (i.e., coke debris) go through the decoke header to the decoke cyclone, which separates the particulate matter from the gaseous combustion products. The particulate matter is dumped from the cyclone into a sealed bin, while the gasses pass to the atmosphere through the decoke stack.

Upon completion of the decoke step, the air flow through the furnace tubes is cut off, and the furnace tube outlet (at this point in 100% steam flow) is re-routed back to the cracked gas header. Thereafter, the furnace firing rate is increased and feedstock is re-introduced to to resume cracking in the normal mode.

As discussed above, there is no production (no cracking of feedstock) in the tubes while in decoke mode.

2.1.2 Hot Standby

The furnace may also operate in a "hot standby" mode. This mode is characterized by low firing (less than or equal to 70% of the maximum firing) during a period when the furnace effluent is not being routed to the decoke stack. The furnace may be operated in this mode to ensure the continued production of steam during times when the unit is operating at reduced rates.

There may or may not be production (cracking of feedstock) in the tubes while in "hot standby" mode.

2.2 Product Recovery

The cracked gas product from the olefins furnace is routed to the common cracked gas header for downstream separation into various olefins products. Along the way, heat is recovered in heat exchangers to generate steam; the steam is used throughout the plant to drive steam turbines which powers major compressors and pumps around the plant.

The cracked gas product contains olefins product fractions from hydrogen and methane to heavy oils, the relative composition of the stream depending on the feed and the furnace yield.

The cracked gas is routed to a quench tower where the gas is quenched in a water or oil stream to recover heavier fractions (oils and liquids).

The cracked gas from the quench tower overheads is then compressed and treated. After compression, the gas is sent to the caustic wash tower to remove acid gases (H_2S and CO_2). (CO_2 is removed in solution, with no process vent of CO_2.) The resulting overhead gas from the caustic wash tower is cooled and then dried in gas dryers to remove any remaining water. The dryers use a molecular sieve with no direct heat addition. Dryer regeneration is conducted in a completely closed system and the used regeneration tail gas is routed to the fuel gas system or a flare (DDM-3101).

The dried cracked gas product is separated into various commercial olefins product streams in a series of quench and distillation steps in distillation towers and splitters. The lighter product streams (C1-C3) require successive refrigeration, which is achieved by using compressed ethylene and propylene as refrigerant in exchangers. The compressors for such refrigeration systems is powered by steam turbines, which steam is partially generated upstream from the exchangers heated by cracked gas and furnace flue gas.

With the proposed new furnace, INEOS projects a net reduction in the demand for steam from external sources (i.e. boilers) [see discussion in section 1.5].

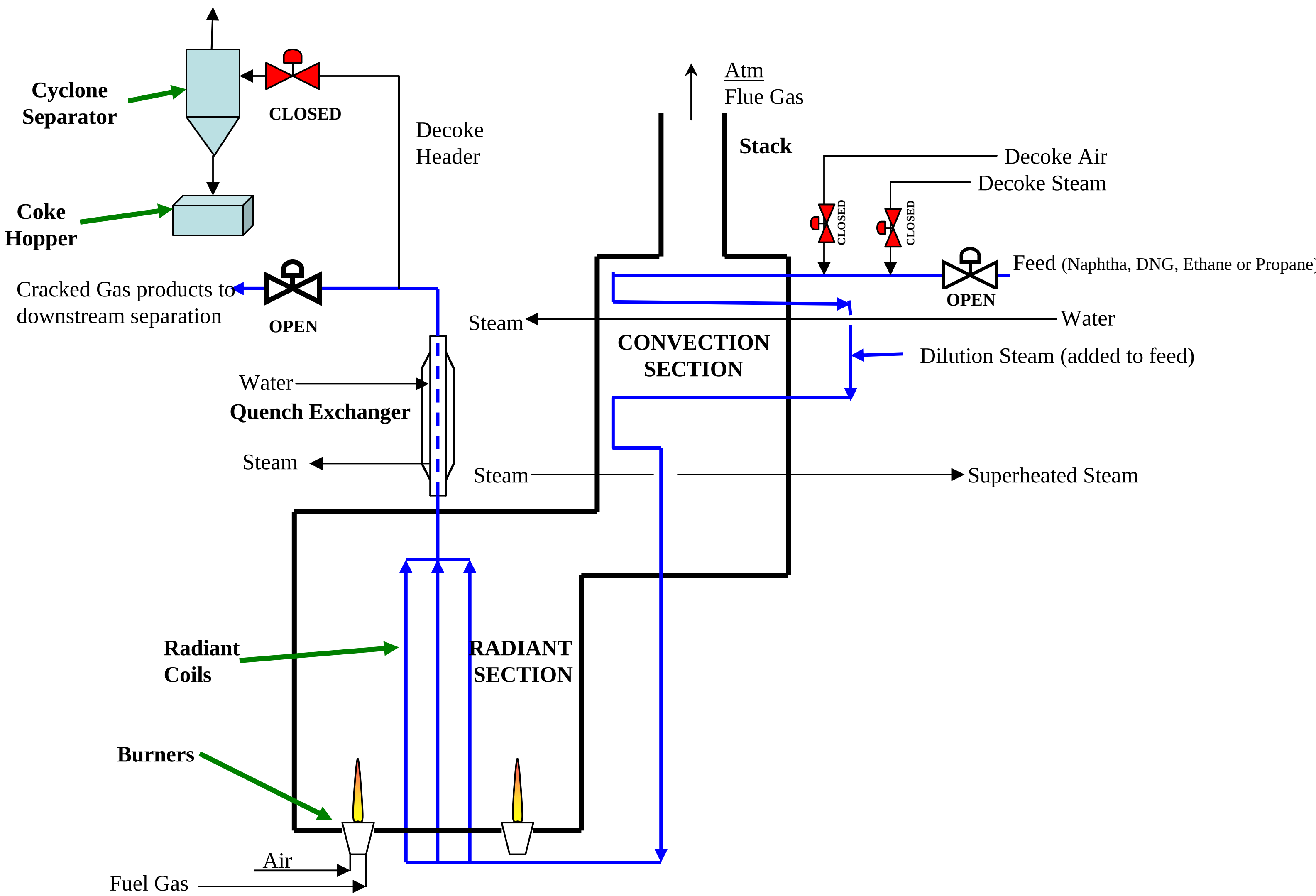
The liquid olefins products (fuel oils, gasoline) are stored in tanks. Fuel oil is shipped via trucks. Gasoline is transported via existing pipeline to customers, and C4 streams are transported via rail cars and barges. The lighter products (propylene, ethylene,and hydrogen) is transported via existing pipeline. Tail gas (methane/hydrogen mixture) is combusted as fuel in the olefins unit complex.

2.3 Flare

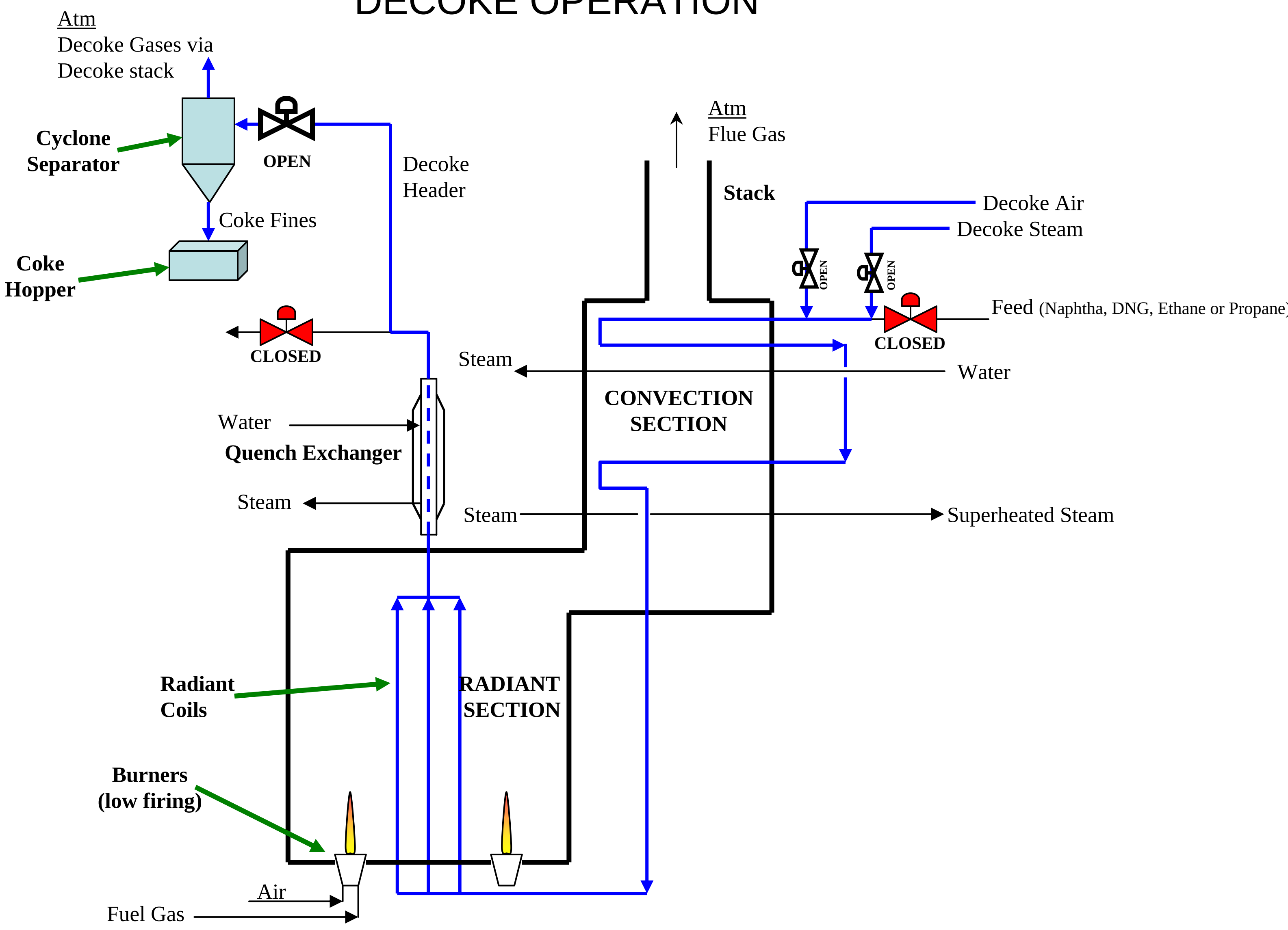
The No. 2 Olefins Unit flare (DDM-3101) is provided to contain and burn smokelessly the hydrocarbon emissions expected under normal operating conditions, as well as normal startup and shutdown operations.

Figure 2-1 | Process Flow Diagram

NORMAL OPERATION



DECOKE OPERATION



Section 3 | Emissions Basis

This section describes and summarizes the emissions associated with the conversion to a Subchapter B permit and the assumptions and methods used in deriving the estimated emission rates. The proposed emissions are based on facility potential to emit, consistent with BACT and authorized emissions from prior permit actions.

3.1 Cracking Furnace

The proposed furnace will have the capability to be fueled with either natural gas or fuel gas from a variety of sources. NO_X and CO emissions are based on vendor guarantees. The maximum allowable (hourly) emissions and annual average emissions for the permit allowable are based on the operating scenario that would result in the highest emissions for each pollutant. The fuel gas composition will contain mostly methane, 1-2% other materials, and hydrogen. The hydrogen content is typically in the range of 30-50% by volume (35% has been used as a conservative case for emissions calculations). The hourly and annual emissions of GHG are based on a carbon balance, using the worst case fuel of natural gas.

3.2 Decoke Cyclone/Stack

Coke is removed during the initial four hours of decoking. Emission factors for CO and PM_{10} were provided by the coke drum manufacturer. Because hydrocarbons are thoroughly steam-purged to the process before the introduction of air to the furnace, there are no expected hydrocarbon emissions (VOC or methane) from the decoke stack during decoking. VOC emissions from the decoke cyclone are due to leakage through block valves in the decoke header which are closed during normal operation. During decoking, CO_2 emissions are created from combusting the carbon build-up on the furnace tubes. Emission rates are based on the anticipated mass of coke and number of decokes per year. It is assumed that 46% of the coke combustion will be emitted in the form of particulates and 51% will be emitted as CO and CO2. INEOS is still in the process of picking a vendor but will meet emission representations in this application. CO is more reactive and will tend to create CO2 once exposed the cooler temperatures at the stack. Particulate emissions are based on the anticipated amount mass of coke in the drum and the appropriate control efficiency is applied.

3.3 Fugitive Components

Emissions from fugitive components are calculated using the applicable SOCMI factor and monitoring program reduction credit. INEOS performs a 28-VHP program for VOC components and AVO inspections for ammonia components. The detector used is not specific for individual hydrocarbon compounds, so leaks of VOC or methane will be detected. Speciations are an overall average distribution and may not represent all operations.

3.4 Ammonia Slip

Ammonia slip emissions from the selective catalytic reduction (SCR) systems are based on the exhaust flowrate and a maximum hourly and annual ammonia slip level (ppmv).

3.5 Maintenance, Startup, and Shutdown

The furnace goes through a decoke before shutdown or maintenance are performed. The startup of the furnace is similar to the re-introduction of feed after the completion of a decoke. Therefore, all Maintenance, Startup and Shutdown (MSS) emissions are a subset of decoking operations.

Section 4 | Best Available Control Technology (BACT)

The PSD regulation requirements of 40 Code of Federal Regulations (CFR) Subsection 52.21(j) require that Best Available Control Technology (BACT) be used to minimize the emissions of pollutants subject to PSD review from a new major source or a modification to an existing major source. Additionally, according to the TCEQ regulation §116.111(a)(2)(C), the proposed facility must be operated with Best Available Control Technology (BACT) for minimizing emissions to the atmosphere with consideration given to the technical practicality and economic reasonableness of reducing or eliminating the emissions from the facility. The pollutants subject to PSD review for the proposed application are PM_{10} and $PM_{2.5}$. (GHG BACT is addressed separately in Section 5.) Additionally, TCEQ's New Source Review (NSR) policy requires BACT.

EPA recommends that the *1990 Draft New Source Review Workshop Manual* be used to determine BACT for PSD pollutants. According to this document, BACT determinations are made on a case by case basis using a "top-down" approach, with consideration given to technical practicability and economic reasonableness. Specifically the "top-down" approach shall include the following steps:

1. Identify all available control technologies;
2. Eliminate technically infeasible options;
3. Rank remaining control technologies;
4. Evaluate the most effective control and document results; and
5. Select BACT.

INEOS utilized the RACT/BACT/LAER Clearinghouse (RBLC) to identify the available control technologies which have been demonstrated and approved for the particulate sources associated with this project. These sources included pyrolysis cracking furnaces and decoke vents. The EPA maintains the RBLC. The RBLC is intended to function as a reference for state and local air pollution control agencies in making BACT/LAER decisions and thus has two basic purposes: 1) to provide state and local air pollution control agencies with current information on case-by-case control technology determinations that are made nationwide; and 2) to promote communication, cooperation, and sharing of control technology information among the permitting agencies.

The RBLC was accessed in a query of BACT using process type and pollutant and looking back over the past ten years. In addition, INEOS referred to TCEQ for BACT for fugitive components. The query results from the RBLC and TCEQ can be found in the Appendix D.

4.1 Cracking Furnace | NO_X, CO, VOC and SO_2 Emissions

Based on guidance from the TCEQ, BACT for cracking furnaces with a design capacity greater than 300 MMBtu/hr is a SCR (achieving 0.03 lb NO_X/MMBtu to 0.06 lb NO_X/MMBtu). The proposed new cracking furnace is rated at 495 MMBtu/hr maximum (HHV) and equipped with a SCR. INEOS will burn high hydrogen fuel (typiclaly 30-50% by volume) with the balance comprised of methane and 1 to 2% other (ethylene, etc.). This will allow INEOS to achieve hourly NO_X emissions of 0.03 lbs NO_X/MMBtu and 0.01 lbs NO_X/MMBtu on an annual average. The higher hourly average is needed to accommodate the high hydrogen fuel. Therefore, INEOS meets current BACT for NO_X.

INEOS will minimize CO and VOC emissions through energy efficient design and utilizing good operating practices. The furnace will normally operate at a temperature greater than 2000° F to minimize VOC and CO emissions. In addition, INEOS will manage excess oxygen, such that CO emissions are minimized. The proposed furnace should operate at 0.044 lb CO/MMBtu. BACT for a furnace is an outlet concentration of 100 ppmv of CO, therefore INEOS meets BACT.

SO_2 emissions from the furnace will be minimized by limiting the short-term sulfur content of the fuel to 5 grains of total sulfur per 100 scf.

The furnaces will be equipped with a CEMS to continuously monitor excess oxygen (diluent), NO_X and CO emission rates. The fuel firing rate (MMBtu/hr) will be continuously monitored. The combination of furnace design, operating practices, and monitoring capabilities meet the criteria for BACT for NO_X, CO, VOC and SO_2.

4.2 Cracking Furnace | PM_{10} and $PM_{2.5}$ Emissions

Emissions of particulate matter (including PM_{10} and $PM_{2.5}$) from natural gas/fuel gas fired furnaces result from inert solids in the fuel and combustion air from unburned fuel hydrocarbons that agglomerate to form particles that are emitted from the exhaust. Using natural gas or fuel gas with a low solids content and efficiency control technology in the furnaces will minimize combustion particulates from the furnace stack. INEOS will operate the furnace with high combustion efficiency and burn clean fuels to ensure thermal efficiency, high production yield and minimized soot and particulate matter emissions, which is BACT. A detailed step by step "top down" BACT discussion is included below.

4.2.1 STEP 1 | Identify All Available Control Technologies

A review of the RBLC found in Appendix D indicates that the only available control technologies are good combustion and the use of clean fuels (refinery gas, fuel gas or natural gas), good engineering design and proper combustion practices for gas fired furnaces, and conducting visible emissions observations. As recommended by EPA, INEOS included natural gas, process gas, and refinery gas combustion devices used in a variety of industries and processes that are similar but significantly different in operation than the proposed cracking furnace.

4.2.2 STEP 2 | Eliminate Technically Infeasible Option

INEOS considers all identified control technologies as technically feasible.

4.2.3 STEP 3 | Rank Remaining Control Technologies

Because there is only one available control technology, ranking is not required

4.2.4 STEP 4 | Evaluate the Remaining Control Efficiencies

Operating the furnace with good combustion results in a higher thermal efficiency. As a result, this reduces the amount of soot formed and particulate emissions.

4.2.5 STEP 5 | Select BACT

INEOS will be operating the cracking furnace with combustion of only natural gas and fuel gas. The fuels will be clean. INEOS will be purchasing a new furnace with all the latest engineering technology to ensure good combustion and therefore minimize particulate emissions. In addition, INEOS will conduct visible emission observations of the furnace stack on a quarterly basis. Therefore, INEOS meets BACT.

4.3 Decoke Cyclone/Stack

Particulate emissions will result from combustion of the coke build-up on the coils of the new furnace; some of which are emitted to the atmosphere through the Decoke Drum. A new decoking drum will be installed in association with this project that will be dedicated to the proposed new furnace.

INEOS researched the RACT/BACT/LAER (RBLC) Clearinghouse and the TCEQ website to identify control methods utilized to control decoking operations. A table summarizing the control determinations for particulates in the RBLC is included in Appendix D. The TCEQ website and the RBLC BACT for decoking emissions are associated with a fluid catalytic cracking unit not a pyrolysis cracking furnace. However, because the vent gas stream and characteristics for the decoking operation are similar, INEOS included these units for BACT determination purposes. INEOS was unable to find any BACT demonstrations specifically for $PM_{2.5}$. INEOS will meet BACT for $PM_{2.5}$ by meeting BACT for PM and PM_{10}.

A detailed step by step "top down" BACT discussion is included below.

4.3.1 STEP 1 | Identify All Potential Control Technologies

Per the RBLC and TCEQ website, the available potential control technologies from decoking include the installation of wet scrubbers/cyclones, good combustion practices and conducting visible emission observations.

4.3.2 STEP 2 | Eliminate Technically Infeasible Option

INEOS considers all identified control technologies as technically feasible.

4.3.3 STEP 3 | Rank Remaining Control Technologies

Because INEOS is proposing to employ all available control technologies, ranking is not necessary.

4.3.4 STEP 4 | Evaluate the Remaining Control Efficiencies

Wet scrubbers/cyclones represent a variety of devices that are effective at removing particulate from exhaust streams with a relatively high efficiency. Scrubbers remove pollutant gases by *dissolving* or *absorbing* them.

Visible emissions observations are made and recorded in accordance with the requirements specified in 40 CFR § 64.7(c) to ensure particulate emissions are minimized. The visible emissions determination shall be conducted when weather conditions permit and should not include water vapor.

4.3.5 STEP 5 | Select BACT

Periodic decoking is inherent to the design and operation of a cracking furnace. Due to metallurgical limits and pressure drop, coking results in taking the furnace offline and temporarily suspending production. INEOS will limit the annual decoking operation to 420 hours.

INEOS will equip the new decoke drum with a control device that will achieve control efficiencies of at least 99.9% for PM, 90% for PM_{10} and 50% for $PM_{2.5}$ and minimize particulate formed through good combustion practices.

INEOS will perform daily visible emission observations of the decoke stack (when in use) to minimize particulate emissions. INEOS is proposing that operating the cracking furnace with best-in-class thermal efficiency to minimize coke build up and therefore decoking emissions, and installing a control device on the decoke drum, should be considered BACT. As part of operating a thermally efficient furnace and practicing good combustion practices, all air pollutants and coke build up are minimized. Therefore, BACT is met.

4.4 Fugitive Components

Per TCEQ's website, current BACT for uncontrolled VOC emissions greater than 25 tpy is a 28 VHP Leak Detection and Repair Program (LDAR). INEOS utilizes TCEQ's 28VHP LDAR program to reduce emissions from VOC process fugitive components. All components designated as "difficult to monitor" are monitored annually. Therefore, BACT is met.

4.5 Ammonia Slip

Because ammonia SCR will be used to control NO_X emissions from the furnace, there will be fugitive components from the piping of ammonia. Based on the TCEQ website, Audio, Visual and Olfactory (AVO) Leak Detection and Repair (LDAR) inspection must be conducted once per shift. INEOS is proposing to conduct AVO once per shift for the ammonia fugitive components associated with this project, therefore BACT is met.

The ammonia slip will be limited to 10 ppmv, corrected to 3% oxygen, (averaged over a 24 hour period) as required in Chapter 117. Short-term average ammonia in the slip may be higher (20 ppmv ammonia). Limiting the amount of ammonia slip will reduce ammonia emissions, therefore BACT is met.

Section 5 | Greenhouse Gas PSD Evaluation and Top-Down BACT Review

INEOS is proposing to install and operate a new cracking furnace and the associated equipment (including decoking drum and fugitives) at the existing No. 2 Olefins Unit at the Chocolate Bayou Plant. The proposed project will occur at an existing major source, and has the potential to emit greater than 75,000 tpy of GHG as CO_2e. The project is scheduled to begin construction after July 1, 2011 and before June 20, 2013. Therefore, the project will meet the definition of a major modification under the current EPA GHG rules. Since EPA has not established national air ambient quality standards (NAAQS) for GHG, the permitting requirements are handled under prevention of significant deterioration (PSD). There are no creditable decreases of CO_2e emissions in the contemporaneous period that would change the PSD applicability determination.

5.1 Relevant Background

On June 3, 2010, EPA published final rules for permitting sources of GHGs under PSD, known as the "Tailoring Rule." The tailoring rule is being implemented in multiple steps. Projects that have permits issued and construction implementation occurring between July 1, 2011 and June 30, 2013 fall into Step 2 of this rule. Therefore, PSD permitting requirements will apply to major modifications that emit greater than 75,000 tpy of GHG as CO_2e at existing major sources even if they do not exceed permitting thresholds for any other pollutants. Under the Clean Air Act (CAA), PSD permit applications are required to:

- Establish and employ best available control technologies (BACT);
- Demonstrate compliance with air quality related values and PSD increments;
- Address impact on Class I areas (e.g. national parks and wilderness area); and
- Assess impacts on soils, vegetation and visibility.

In December 2010, EPA finalized a rule that designates EPA as the permitting authority for GHG emitting sources that will remain in effect until EPA approves a state implementation plan (SIP) that allows Texas to regulate GHGs.

5.2 BACT Discussion

In the EPA March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA recommends that the *1990 Draft New Source Review Workshop Manual* be used to determine BACT for GHG. According to this document, BACT determinations are made on a case by case basis using a "top-down" approach, with consideration given to technical practicability and economic reasonableness. Specifically the "top-down" approach shall include the following steps:

1. Identify all available control technologies;
2. Eliminate technically infeasible options;
3. Rank remaining control technologies;
4. Evaluate the most effective control and document results; and
5. Select BACT.

To identify all potential control technologies, INEOS reviewed the EPA's Sector GHG control white papers for petroleum refineries, natural gas combustion, and biomass energy. These papers were prepared by the Sector Policies and Programs Division, Office of Air Quality Planning and Standards. Although these documents address sources that are significantly different than those associated with this project, a sector paper on cracking furnaces and decoking is not currently available. When performing a "top-down" BACT analysis, an applicant is required to review control technologies for similar sources. These sources have been identified as the most similar and available to those associated with the proposed project. In addition, INEOS has researched the RACT/BACT/LAER Clearinghouse (RBLC) and the American Institute of Chemical Engineers (AIChE) website, webinars and papers. The only control method identified for control of CO_2 from decoking is good combustion practices to minimize the amount of coke formed. Because the furnace burns at half its firing rate during decoking, it is less energy efficient. Therefore, INEOS will minimize GHG emissions limiting the hours of decoking operations. The database search was conducted for similar processes. The results of the RBLC are included in Appendix D.

The overall energy efficiency of the source through technologies, processes and practices at the facility should be included in the BACT determination. In general, a more energy efficient technology burns less fuel. Energy efficiency technologies in the BACT analysis helps reduce the production of combustion of GHG and other regulated NSR pollutants. Because the equipment associated with the proposed project will all be new, the equipment should be of the best engineering design and equipped with the latest technology to ensure energy efficiency. Performance benchmarking is an available tool that is useful in assessing energy efficiency. There are a number of resources available for benchmarking facilities, including EPA's ENERGY STAR program for industrial sources. ENERGY STAR has developed sector specific benchmarking tools called Energy Performance Indicators (EPI). These energy performance indicators are included in the EPA sponsored document *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Manager,* Document Number LBNL-964E, dated June 2008. This tool is especially useful for GHG because the traditional method of collecting information, such as the RBLC, has yet to be populated with updated case-specific information due to the infancy of the program. INEOS utilized this document, as a resource to identify performance benchmarking data for cracking furnaces, to complete the BACT GHG evaluation. This resource is referenced as a tool that can be used for benchmarking for GHG BACT determination and GHG control measures in the EPA guidance document PSD AND TITLE V PERMITTING GUIDANCE FOR GREENHOUSE GASES (dated March 2011). Section 8 Furnaces/ Process Heaters of this document identifies the average thermal efficiency of furnaces to be 75-90% and the theoretical maximum efficiency is around 92% (HHV). This maximum efficiency accounts for unavailable heat losses and dew point considerations. Section 8 of this document is included in Appendix E as a reference. The furnace proposed in association with this project will be designed to meet the theoretical maximum efficiency of 92% HHV based on vendor data Thermal efficiency, as noted in Section 8 of the Energy Star document, is limited in practicality by flue gas condensation. The temperature of the incoming process stream (boiler feed water) that the flue gas is used to heat is also close to this same number.

GHG emissions are associated with the cracking furnace, decoking drum and fugitive emissions. A detailed GHG BACT discussion is included below for each source associated with the proposed project. INEOS is still in the vendor selection phase of this project. This application represents the most likely operating scenario for purposes of preparing this application, but the actual operations may vary. However, INEOS is committing to meet the emission limitations and control measures represented in this application.

5.3 Cracking Furnace BACT Discussion

The majority of the contribution of GHG associated with the project is from the furnace. Stationary combustion sources primarily emit CO_2, but they also emit a small amount of N_2O and CH_4. Because INEOS will be installing a new furnace in association with this project, it will be equipped with all the latest technology for optimum thermal efficiency. The proposed cracking furnace will be fueled by natural gas and plant fuel gas. The combined fuel gas composition will contain mostly methane, 1-2% other materials (including ethylene) and hydrogen (typically 30-50% by volume). The furnace will be equipped with an ammonia slip selective catalytic reduction system (SCR) to reduce NO_X emissions. Consistent with federal NSPS and MACT for combustion devices, demonstration of compliance with control requirements do not apply during periods of startup, shutdown and malfunction.

5.3.1 Step 1 | Identify All Available Control Technologies

The best way to control combustion related GHG and other regulated pollutants is through thermal efficiency achieved through design and operations. Good combustion practices are considered BACT. These practices are based on EPA guidance located at http://www.epa.gov/ttnatw01/iccr/dirss/gcp.pdf and are summarized in Table 5-1. INEOS will comply with the practices and standard outlined in this table.

INEOS has identified the following currently available control technologies for controlling GHGs from cracking furnaces:

1. Carbon Capture and Storage (CCS) as add-on control; and
2. Energy Efficient Design and Operation
    - Efficient Furnace and Burner Design and Operation
    - Periodic Tune Ups and Maintenance
    - Oxygen Trim Control
    - Heat Recovery
    - Low-Carbon Fuel
    - Preheating Fuel Stream

5.3.2 Step 2 | Eliminate Technically Infeasible Options

Ceramic coatings for furnace tubes were tested in the ethylene industry—including at our plant site—many years ago. This technology was examined both for its potential to improve heat transfer and its potential to reduce coking. The coatings proved impractical because of a lack of adhesion to the metal surface. This was aggravated because of the thermal cycling of the tubes (i.e., decoking) in Olefins furnaces. To INEOS's knowledge, there is no ongoing development concerning ceramic coatings for ethylene furnace tubes.

INEOS considered all other identified control technologies as technically feasible options.

5.3.3 STEP 3 | Rank Remaining Control Technologies

Because thermal efficiencies are work practice standards, it is difficult to identify discriminate control efficiencies for ranking. INEOS used *Available and Emerging Technology for Reducing Greenhouse Gas Emission from the Petroleum Industry* dated October 2010 and *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Manager,* Document Number LBNL-964E, dated June 2008 to identify any available control efficiencies. The efficiency improvements/GHG reductions identified are as follows:

- Efficient Furnace and Burner Design (10%)
- Periodic Tune Ups and Maintenance (1-10%)
- Oxygen Trim Control (1-3%)
- Heat Recovery (8-18%)
- Low-Carbon Fuel (10-15%)
- Preheating Fuel Stream (10-15%)
- CCS (not a feasible option for the project due to technical, environmental, and economic reasons, as discussed in Step 4)

5.3.4 STEP 4 | Evaluate the Remaining Control Efficiencies

Because the following identified control efficiencies include operating practices and design, it is difficult to claim a control level for each. Studies or data are not readily available that identify a specific control level. INEOS is implementing all the control technologies identified as BACT in Step 3 except for CCS. CCS is not considered to be feasible, based on its lack of available technologies and negative environmental impacts, as well as its negative economic impacts. However, per EPA guidance, EPA has identified CCS as an add-on control technology that is available for the Stack GHG that must be evaluated as if it were technically feasible. The emerging CCS technology is an end of pipe add-on control method comprised of three stages (capture/compression, transport and storage).

5.3.4.1 CCS

Capture, Transport, and Storage

CCS would require adequate space for equipment to capture the flue gas exhaust and to separate and pressurize the CO_2 for transportation. The proposed project involves a cracking furnace burning low carbon content fuel. Therefore, the resulting low pressure exhaust stream has a lower level of CO_2

(concentration and volume) than would be produced at other facilities (e.g. natural gas compressor stations or coal-fired utility).

Storage
All CCS projects require geological storage (e.g. oil and natural gas reserves, un-mineable coal reserves, or underground saline formations). The logistical hurdles associated with geological storage are the availability of storage capacity and the potential environmental impacts associated with long term storage of CO_2. For example, the effect of dissolving CO_2 in brine and the resulting brine displacement still needs to be resolved.

Feasibility
According to the guidance documents for GHG permitting and for reducing carbon dioxide emissions from bioenergy, EPA has concluded that although CCS is available it does not necessarily mean it would be selected as BACT due to its technical and economic infeasibility. In addition, EPA supports the conclusion of the Interagency Task Force on Carbon Capture that although current technologies could be used to capture CO_2 from new and existing plants, they are not ready for widespread implementation. This is primarily because they have not been demonstrated at the scale necessary to establish confidence in its operations.
The goal of CO_2 capture is to concentrate the CO_2 stream from an emitting source for transport and injection at a storage site. CCS requires a highly concentrated, pure CO_2 stream for practical and economic reasons. The primary source of CO_2 associated with this project is an exhaust gas stream from a combustion device. The exhaust gas stream from the combustion device has unique characteristics that make it technically difficult to employ CCS. These characteristics include:

- multiple contaminants (e.g. particulate matter)
- low pressure
- high temperature
- high volume
- low CO_2 concentrations

The exhaust gases from combustion require the installation and operation of additional equipment to capture, separate, cool and pressurize the CO_2 for transportation. The CO_2separation would require the removal of PM from the streams without creating too much back pressure on the upstream system. In addition, it would require compression to increase the pressure from atmospheric to a pressure required for efficient CO_2 separation (~ 700 psia) and after separated additional compression would be required to pressurize the CO_2 to that of the Denbury pipeline (estimated to be ~2200 psia). In practice, a series of compressor would be needed, which would increase the overall capital and operational cost. However, for simplicity the cost estimate is based on just one compressor to increase the pressure from atmospheric to the final required pressure of 2200 psia. A cooling mechanism (e.g., complex heat exchangers) would also be required to reduce the temperature of the streams from around 400°F to less than 100°F prior to separation, compression, and transmission. The cooling system would also require additional compression. To achieve separation an amine unit or an equivalent would be required to capture the CO_2, therefore the equipment (including final compression) must be designed to handle acidic gases, which results in additional cost. The entire system would require high energy consumption/cost to compress, separate and cool the exhaust gas for processing and transport requirements. If the compression system were run by electrical engines, this would require an additional energy consumption of ~ 3 MW and the amine unit would be a source of additional emissions. The combination on all the additional equipment and operations described above would have an additional adverse impact on the environment.

The National Energy Technology Laboratory (NETL) is part of DOE's national laboratory system and is owned and operated by DOE. NETL supports DOE's mission to advance the national, economic, and energy security of the United States. When available INEOS utilized vendor supplied cost estimates. Otherwise, INEOS utilized the March 2010 NETL Document Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447 to estimate the cost associated with the pipeline and associated equipment. This document provides a best estimate of transport, storage, and monitoring costs for a "typical" sequestration project.

CO_2 transport costs are broken down into three categories, as follows:

- **Pipeline/Transfer Costs –** Pipeline costs are derived from the Oil and Gas Journal's annual Pipeline Economics Report for natural gas, oil, and petroleum projects which are expected to be analogous of the cost of building a CO_2 pipeline. The cost estimate includes pipeline materials, direct labor, indirect costs, and right of way acquisition as a function pipeline length and diameter and is based upon a study completed by the University of California.
- **Related Capital Expenditures –** Capital costs associated with CCS are estimated based upon the DOE/NETL study, Carbon Dioxide Sequestration in Saline Formation – Engineering and Economic Assessment for typical costs associated with pipeline. The costs were adjusted to include a CO_2 surge tank, compression and cooling equipment as well as a pipeline control system. Miscellaneous costs also include surveying, engineering, supervision, contingencies, allowance, overhead, and filing fees. Note the cost estimate below does not include the additional capital associated with the amine unit or cooling equipment, although this would be required. The cost per ton demonstrates that CCS is economically infeasible even without including this additional cost.
- **O&M Costs –** O&M costs are based on the DOE/NETL report Economic Evaluation of CO_2 Storage and Sink Enhancement Option on a cost/pipeline length basis.

Finally, assuming that CCS were readily available and could be implemented on a large-scale basis without negative environmental impact, INEOS would still have to resolve several logistical issues including obtaining right of way (ROW) for the pipeline and finding a storage facility or other operation that would be available to receive and handle a large volume of CO_2.

The nearest identified pipeline that may transport CO_2 is approximately 14 miles from the Plant. For the purpose of this BACT analysis, INEOS has determined that the proposed Denbury pipeline is the nearest potentially available CO_2 pipeline. However, the Denbury pipeline system is not currently operational and not expected to be so for the next few years. The cost associated with CCS is over $230 MM, or approximately \$150/ton of CO_2 reduced. A detailed cost analysis is attached. Please refer to attached Table 5-1 for details of the cost estimate. Based on the issues identified above, CCS is not considered a technically, economically, or commercially viable control option for this project.

Table 5-1 | CCS Cost Estimate

Table 5-1
ESTIMATED COST OF CCS STACK CO_2 CONTROL+A30

CO_2 Pipeline Data

Pipeline Length	13.6 miles		
Pipeline Diameter	8 inches		
Short Ton of Stack CO_2	262,449 tons/yr	719.04 tons/day	
Captured Short Ton of CO_2 (90%)	236,204 tons/yr	647.14 tons/day	

Pipeline Cost Breakdown

Cost Type	Units	Cost	
Pipeline Costs			
Pipeline Materials	$ Diameter (inches), Length (miles)	$64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D + 26,920)	$ 1,413,348.90
Pipeline Labor	$ Diameter (inches), Length (miles)	$341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)	$ 5,589,243.17
Pipeline Miscellaneous	$ Diameter (inches), Length (miles)	$150,166 + $1.58 x L x (8,417 x D + 7,234)	$ 1,752,526.16
Pipeline Right of Way	$ Diameter (inches), Length (miles)	$48,037 + $1.20 x L x (577 x D +29,788)	$ 609,510.28
Other Capital			
Compression	$ (vendor data)	$14,000,000	$ 14,000,000.00
Cryogenic Units/Amine Units /Dehydration	$ (vendor data)	$200,000,000	$ 200,000,000.00
CO_2 Surge Tank	$	$1,150,636	$ 1,150,636.00
Pipeline Control System	$	$110,632	$ 110,632.00
O&M			
Liability		$5,000,000	$ 5,000,000.00
Fixed O&M	$/mile/year	$8,632	$ 113,723.20
Fixed O&M	$ (vendor data)	$1,300,000.00	$ 1,300,000.00
		Total Pipeline Cost	**$ 231,039,619.70**

Amortized Cost

Total Capital Investment (TCI) =			**$ 224,625,896.50**
Capital recovery factor (CRF) [1] = $i(1+i)^n/((1+i)^n - 1)$			$ 0.15
i = interest rate =	0.08		
n = equipment life =	10 years		
		Amortized installation costs = CRF * TCI =	**$33,475,882.50**

Total Pipeline Annualized Cost	**$34,775,882.50**
Cost per short ton CO_2	**$ 147.23**

NOTE: This cost estimate sheet does not include O&M costs associated with the amine unit

5.3.4.2 Energy Efficient Design and Operation

Because INEOS will be installing a new furnace in association with this project, it will be equipped with all of the latest technology for optimum thermal efficiency. This more energy-efficient technology will require less fuel and therefore result in lower emissions. INEOS has selected an energy-efficient technology, which will result in fewer overall emissions of all air pollutants per unit of energy produced. This can translate into collateral reduction in other pollutants including GHGs. While minimizing GHG, the burner design will still address safety and environmental concerns, most notably the reduction of NO_X emissions. An additional furnace will give INEOS the opportunity to utilize energy more efficiently by allowing operational efficiency and optimization, decreasing the load on existing furnaces and boilers, and allowing INEOS to better manage maintenance and decoking operations. EPA believes that it is important to consider options that improve the overall energy efficiency of the source through technologies, processes and practices.

In addition, thermal efficiency can be achieved through good operating practices and regularly scheduled maintenance. The furnace will be maintained according to specific operating and maintenance procedures at INEOS that will incorporate the vendor's recommendations. The first step to energy efficiency is reducing exhaust losses and the second is recovery of exhaust gas heat.

These operating practices include:

- **Periodic Tune Ups and Maintenance**- The furnace will be periodically tuned to maintain optimal thermal efficiency. In addition, maintenance will be performed routinely per vendor recommendations or the facility's maintenance plan. These measures include checking the fuel gas flow meter annually, the oxygen control analyzers quarterly, the burner tips on an as-needed basis and replacing or servicing components as needed.
- **Oxygen Trim Control** - Excess air will be limited to the amount necessary to ensure complete combustion. Too much excess air may lead to inefficient combustion, since energy must be used to heat the excess air. Oxygen analyzers are used to optimize the fuel/air mixture. INEOS will carefully manage the amount of excess oxygen added to the system (2 to 3.5 mol% dry excess during normal operation). INEOS also plans to include carbon monoxide analyzers at part of the Continuous Emissions Monitoring System (CEMS) to ensure proper combustion and optimization of excess air.
- **Heat Recovery -** The hot effluent from the cracking furnace is cooled in the primary and secondary quench exchangers that produce high pressure steam to recover energy and reduce the overall energy use in the plant. Tertiary quench exchangers also recover heat and contribute to overall energy efficiency. Finally, the furnace convective section is used to pre-heat or superheat boiler feed water, hydrocarbon feed, dilution steam, and high pressure steam to the extent that the final exiting flue gas temperature is reduced to its practical limit (i.e., the dew point temperature of the flue gas and the temperature of the process streams being heated). INEOS proposes a stack temperature limit of 340°F. This provides a margin of safety above the dew point temperature. INEOS's

operating experience with similar furnaces indicates that this safety margin is necessary for the following reasons:

- It is necessary to operate with sufficient excess oxygen to ensure that CO emissions are controlled.
- While the excess oxygen is controlled automatically by adjusting the furnace draft, the air entering each burner must be manually controlled. This is because of the positioning of the burners away from the side wall of the furnace in order to ensure internal flue gas recirculation for control of NOx emissions.
- Under some operating conditions, it is desirable to maximize the production of steam. This can be achieved by adjusting the excess oxygen, which can raise the volume of flue gas and the stack temperature.

- **Low-Carbon Fuel -** Another method to minimize CO_2 emissions is through fuel switching/selection. INEOS is using a combination of natural gas which has the lowest typical CO_2 emission factors and process gas which has lower carbon content due to the high volume of hydrogen. The combined fuel gas composition will contain mostly methane, 1-2% other materials (including ethylene) and hydrogen. The lower carbon content has less carbon available to convert to CO_2 and therefore lower emissions. Some of the hydrogen produced by the No. 2 Olefins process is sold as a chemical product and some is used as fuel. Market conditions will dictate how much hydrogen is sold. Market conditions such as the cost of various feedstocks can also affect the total amount of hydrogen produced. Therefore, 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.
- **Condensate Recovery** - Steam condensate from this equipment is routinely recovered as feed water for the steam-producing equipment at the plant. INEOS will incorporate this proposed furnace into its existing condensate recovery system.
- **Heat Exchanger Maintenance** - There are three heat exchangers involved in the furnace. The primary and secondary exchangers cool the cracked gas effluent by producing steam from boiler feed water. The tertiary exchanger cools the cracked gas effluent by pre-heating the feed. The cracked gas effluent remains in the gaseous state through all three exchangers, and is not expected to have any fouling. INEOS treats the boiler feed water to remove dissolved solids and control pH and corrosion, and has no experience with any fouling in this service. The feed material is also gaseous, and is not expected to have any fouling. However, overall efficiency of these exchangers is monitored, and cleaning will be performed during normally scheduled maintenance periods if required.

In order to determine that the chosen design achieves optimum energy efficiency, INEOS used benchmarking information from the five companies from which INEOS received proposals. Table 5-2 notes the overall furnace efficiency from the five designs considered by INEOS. In general, the five modern designs are quite similar in performance. The previous designs have much lower efficiency.

Table 5-2 | Benchmarking Design Data on Efficiency

	Overall Furnace Efficiency, %
Chosen Design	92.6
Design A	93.6
Design B	93.1
Design C	93.2
Design E	93.9
Existing (1993)	92.2
Existing (1976)	89.0
Existing (1973)	85.0

Availability is defined as the hours where the furnace is in hydrocarbon cracking service (i.e., excludes decoking and other downtime) divided by total hours in the year. During periods of decoking, energy is being input to the furnace with no production of products. Therefore, a higher availability equates to a more efficient furnace. The chosen design has an availability above the average of the modern designs.

	Annual Availability, %
Chosen Design	96.83
Design A	95.21
Design B	97.78
Design C	96.39
Design E	95.89
Existing (1993)	96.66
Existing (1976)	96.58
Existing (1973)	95.62

Ethylene yield is defined as the percentage of ethane converted to ethylene by the furnace. (Ethane is chosen because it is the design feedstock.) A higher yield provides for making the same amount of useful products with less heat input. The chosen design is signficantly (at a minimum, 2%) higher on this measurement. In other words, the selected design allows the production of the design amount of ethylene with 33 million pounds less ethane feed than the average of the modern designs.

	Pounds ethylene per pound ethane
Chosen Design	0.573
Design A	0.552
Design B	0.561
Design C	0.550
Design E	0.545
Existing (1993)	0.52
Existing (1976)	0.49
Existing (1973)	0.49

Steam is produced in the convective section of the furnace as the secondary recovery of heat (i.e., after the cracking process itself). If a furnace design results in a lower steam production rate from the convective section, the site must make up the difference from stand-alone boilers and cogeneration facilities. However, this is not accounted for directly in a measurement of the GHG emissions per pound of production. The chosen design produces an average amount of steam among the five designs.

	High-pressure Steam (klbs/hr)
Chosen Design	177
Design A	178
Design B	175
Design C	182
Design E	169
Existing (1993)	105
Existing (1976)	70
Existing (1973)	70

INEOS also considered the fact that the site currently operates five furnaces with a nearly identical design to the one proposed. This minimizes the time it will take to develop the operating expertise necessary to achieve the emissions targets (for emissions of GHG and criteria pollutants).

The difference between the efficiency of the chosen design (92.57%) and the maximum of all designs considerred (93.9%) is approximately 1.33%. Based on annual emissions of 216,667 tpy, the maximum amount of additional GHG emissions would be 2,817 tpy.

When all of the above factors are considered, INEOS has calculated that the furnace will achieve GHG emissions per pound of ethylene of 1.04 lb/lb (24-hour rolling average) and 0.85 lb/lb (365-day rolling average). (See calculations below.) The overall GHG emissions per pound of ethylene product for the chosen design compare favorably to EPA's draft permit for another olefins cracking furnace in the state.

The selected design allows for production of the design ethylene using 33 million pounds per year less ethane feed input when compared to the average of the modern furnaces, which is also an important measure of efficiency via source reduction.

60,413 lb/hr CO2e ÷ 58,200 lb/hr ethylene maximum = 1.04 lb CO2e/lb ethylene
216,667 tpy CO2e ÷ 254,916 tpy ethylene maximum = 0.85 lb CO2e/lb ethylene

5.3.5 STEP 5 |Select BACT

INEOS is proposing that a thermally efficient furnace and operating under the parameters outlined above meets BACT requirements for CO_2. INEOS is proposing to employ all of the control identified in Step 4 and Table 5-3. Table 5-3 also outlines the proposed Monitoring, Recordkeeping and Reporting (MRR) requirements.

Table 5-3 | Proposed Practices and MRR for GHG form Cracking Furnace

Good Combustion Technique	Practices	Standard
Periodic Tuneups and Maintenance	Training operators on applicable equipment and procedures	Record annual operating hours of decoke
	Perform scheduled maintenance per official documented maintenance procedures, that are updated with equipment and practice changes and based on vendor recommendations	Equipment maintained by personnel with training specific to equipment
	Maintenance logs/recordkeeping	
Oxygen Trim Control (Fuel/Air Ratio)	Adjust the amount of excess based on oxygen analyzer	Gross adjustment of air will be done at the burners after significant changes in firing rate and/or ambient conditions. Fine adjustment will be done continuously to control O2 in the furnaces in a range of 2-3 vol%, by adjusting the draft pressure.
	Adjust air/intake at burners based on Continuous Emissions Monitoring System (CEMS) for CO	
Heat Recovery	Collect effluent heat from the furnace and recover and reuse the heat throughout the process by design of operations to the extent that the final exiting flue gas temperature is reduced to its practical limit	Record flue gas temperature
		Record amount and temperature of steam produced
Low Carbon Fuel (Fuel Quality)	Daily Fuel sampling [40 CFR § 98.34(b)(3)(E)] using a gas chromatograph that is operated, maintained, and calibrated according to manufacturer's instructions [40 CFR § 98.34(b)(4)] Fuel flow monitoring will be continuous using a meter meeting the requirements of 40 CFR § 98.3(i) and 98.34(b)(1).	Fuel analysis
	Semi-annual testing for natural gas [40 CFR § 98.34(b)(3)(A)]	

5.4 Decoking BACT Discussion

GHG emissions consist of CO_2 emissions from combustion of the coke build-up on the coils of the new furnace, some of which are emitted to the atmosphere through the Decoke Drum. A new decoking drum will be installed in association with this project that will be dedicated to the proposed new furnace. The total estimated annual CO_2 emission rate is only a minor contribution to the total GHG emissions. However, for completeness it is addressed in this BACT analysis.

INEOS researched the RACT/BACT/LAER Clearinghouse for control methods utilized to control decoking operations. There were two entries for decoking processes in the RBLC. No control methods were identified with either entry. BACT determination for CO_2 updated from decoking operations at this facility was defined as proper design operation of the furnace, therefore minimizing coke build-up. No additional conditions or monitoring requirements were required for this project for BACT.

5.4.1 STEP 1 | Identify All Potential Control Technologies

There are currently no existing demonstrated control technologies for CO_2 emissions from decoking operations. CO_2 emissions can be minimized by reducing the required decoking frequency through proper design and operation. This is the only technically feasible means of minimizing emissions.

5.4.2 STEP 2 | Eliminate Technically Infeasible Option

INEOS considers all identified control technologies as technically feasible.

5.4.3 STEP 3 | Rank Remaining Control Technologies

Because there is only one available control technology, ranking is not required

5.4.4 STEP 4 | Evaluate the Remaining Control Efficiencies

Periodic decoking is inherent to the design and operation of a cracking furnace. As part of operating a thermally efficient furnace, all air pollutants and coke build-up are minimized. Coke acts as insulation on the furnace coils; therefore more fuel gas is required to reach the required temperature. Due to metallurgical limits and pressure drop, coking results in taking the furnace offline and temporarily suspending production. Therefore, INEOS will limit the total annual hours of decoking operation, which will assist in minimizing CO_2 emissions.

5.4.5 STEP 5 | Select BACT

INEOS will minimize the number and duration of decoking operations, which should minimize the associated emissions. INEOS will limit the annual decoking operation to 420 hours/yr. INEOS proposes to monitor the number of hours that the furnace is decoking as the appropriate MRR for Decoking. INEOS proposes this meets BACT.

5.5 Process Fugitives BACT Discussion

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The total estimated annual methane emissions as CO_2e have a very minor contribution to the total GHG emissions. However, for completeness it is addressed in this BACT analysis.

5.5.1 STEP 1 | Identify All Potential Control Technologies

The only identified available control technology for process fugitive emissions of CO_2e is use of a leak detection and repair (LDAR) program. LDAR programs are designed to control VOC emissions and vary in stringency.

5.5.2 STEP 2 | Eliminate Technically Infeasible Option

The only available control technology for fugitives is LDAR, which is technically feasible.

5.5.3 STEP 3 | Rank Remaining Control Technologies

Because there is only one available control technology, ranking is not required.

5.5.4 STEP 4 | Evaluate the Remaining Control Efficiencies

LDAR is currently only required for VOC sources. Methane is not considered a VOC, so LDAR is not required for streams containing a high content of methane. TCEQ's 28VHP LDAR is currently the most stringent program, which can achieve efficiencies of 97% for valves. INEOS will perform TCEQ's 28VHP program on all hydrocarbon lines associated with this project, this will result in a reduction of VOC and any associated methane (GHG) emissions from these piping components.

5.5.5 STEP 5 | Select BACT

INEOS proposes that conducting TCEQ's 28VHP for all hydrocarbon components associated with this project, and thus controlling any associated GHGs, as BACT.

5.6 Preconstruction Monitoring

EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air.

5.7 Impacts Analysis and Preconstruction Monitoring

Ambient Air monitoring for GHGs is not required because EPA regulations provide an exemption in sections 52.21(i)(5)(iii) and 51.166(i)(5)(iii) for pollutants that are not listed in the appropriate section of the regulations, and GHGs are not currently included in that list. But sections 52.21(m)(1)(ii) and 51.166(m)(1)(ii) of EPA's regulations apply to pollutants for which no NAAQS exists. However, GHG is not considered to affect ambient air quality as defined in Section 52.21(m)(1)(ii) or 51.166(m)(1)(ii) as was intended when these rules were written. This is consistent with the EPA Tailoring Rule and includes the following statement with respect to these requirements:

"There are currently no NAAQS or PSD increments established for GHG, and therefore these PSD requirements would not apply for GHG, even when PSD is triggered for GHG."

Because there are currently no NAAQS or PSD increment established for GHG no further assessment is required.

At TCEQ's request, INEOS has completed a modeling impacts analysis. The results of this analysis are included below. All predicted Project impacts were below the respective Significant Impact Levels (SILs), as the summary table below shows, therefore, no additional modeling analyses (e.g., multi-source for NAAQS) are required and there would be no impairment to the soils and vegetation that would occur as a result of the modification. The results of the modeling request submitted to TCEQ are included in the Table 5-4.

Table 5-4 | Maximum Predicted Project CO, NO_2, $PM_{2.5}$, PM_{10}, and SO_2 Impacts

Criteria Air Pollutant	Averaging Period	EPA/TCEQ Significant Impact Level (µg/m³)	Maximum Predicted Project Impact (µg/m³)	Percent of Applicable Significant Impact Level (%)	Is the Maximum Predicted Project Impact Above the Applicable Significant Impact Level?
CO	8-Hour	500	46.9[a]	9.4%	**No**
CO	1-Hour	2,000	65.1[a]	3.3%	**No**
NO_2	Annual	1	0.16[a,b]	16%	**No**
NO_2	1-Hour	7.54	3.14[a,b]	41.6%	**No**
$PM_{2.5}$	Annual	0.3	0.06[c]	20.0%	**No**
$PM_{2.5}$	24-hour	1.2	0.47[c]	39.2%	**No**
PM_{10}	Annual	1	0.11[d]	11.0%	**No**
PM_{10}	24-hour	5	0.94[d]	18.8%	**No**
SO_2	Annual	1	0.005[a]	0.5%	**No**
SO_2	24-hour	5	0.05[a]	1.0%	**No**
SO_2	3-hour	25	0.1[a]	0.4%	**No**
SO_2	1-hour	7.8	0.11[a]	1.4%	**No**
SO_2	30-minute	20.42[e]	0.11[a]	0.5%	**No**

[a]The maximum project impact predicted using one year (1988) of TCEQ-provided IAH/LCH (Houston, Texas/Lake Charles, Louisiana) meteorological data for a medium roughness length location.

[b]The EPA-recommended 1-hour NO_X-to-NO_2 conversion rate of 0.8 was used to scale the 1-hour and annual NO_2 concentrations.

[c]The maximum project impact predicted using a five-year (1987-1991) concatenated TCEQ-provided IAH/LCH meteorological data record for a medium roughness length location.

[d]The maximum project impact predicted using five individual years (1987-1991) of TCEQ-provided IAH/LCH meteorological data record for a medium roughness length location.

[e]The Texas 30-minute property-line SO_2 standard is 1,021 µg/m³. Therefore, the significant impact level for 30-minute SO_2 is 2% of 1,021 µg/m³, or 20.42 µg/m³.

Section 6 | Considerations for Granting a Permit

As required by Sections IX and X of the TCEQ PI-1 permit application form, this section addresses the assurance of regulatory compliance by the proposed installation and operation of a new cracking furnace and associated equipment. The requirement contained in 30 TAC §116.111, General Application, states:

> *"The emissions from the proposed facility will comply with all rules and regulations of the commission and with the intent of the Texas Clean Air Act (TCAA), including the protection of the health and property of the public."*

As outlined in the following evaluation, the emissions from the proposed facilities will comply with all rules and regulations of the TCEQ and with the intent of the TCAA, including protection of the health and property of the public.

6.1 Chapter 101 | General Rules

This facility will comply with all the requirements of the TCEQ General Rules. Some notable rule compliance procedures are summarized below.

§ 101.2 Multiple Air Contaminant Sources or Properties

This section does not apply to this facility or project.

§ 101.3 Circumvention

INEOS does not currently use, nor does it plan to implement, any plan, activity or device that would conceal or appear to minimize the effects of an emission which would otherwise constitute a violation of the TCAA or regulations.

§ 101.4 Nuisance

Routine emission of air contaminants from the proposed facility are not expected to injure or adversely affect human health or welfare, or affect plant, animal life, or property in any way.

§ 101.5 Traffic Hazard

Emissions from this facility are not in such a quantity that would cause traffic hazards or interference in the surrounding areas.

§ 101.8 Sampling

INEOS will perform sampling as required by the TCEQ.

§ 101.9 Sampling Ports

If requested, INEOS will comply with this section as required by the TCEQ.

§ 101.10 Emissions Inventory Requirements

If requested, INEOS will file the appropriate emissions data to the agency on forms provided by the agency. It should be noted that INEOS submits completed Emissions Inventories annually.

§ 101.13-19 Administrative Provisions

INEOS will comply with the applicable rules in these sections.

§ 101.20 Compliance with Environmental Protection Agency Standards

INEOS's Chocolate Bayou Plant will meet all the applicable requirements of 40 CFR Part 60 (NSPS), Subparts A, Db, K, Kb, GG, VV, NNN and RRR.

The pyrolysis cracking furnace is subject to the VOC vent control requirements of NSPS Subpart RRR. All furnace process gases are discharged from the furnaces to the recovery section of the facility which consists of Distillation Units already subject to NSPS Subpart NNN. The organic compounds from the recovery section will typically be recovered with more than 99%.

INEOS's Chocolate Bayou Plant will meet all the applicable requirements of 40 CFR Part 63 (NESHAPS), Subparts A, and XX.

INEOS has addressed the PSD requirements associated with this application in Section 1.2 of this document.

§ 101.21 The National Primary and Secondary Ambient Air Quality Standards

The Chocolate Bayou Plant will continue to be operated in compliance with all applicable National Primary and Secondary Ambient Air Quality Standards (NAAQS).

§ 101.23 Alternate Emission Reduction ("Bubble") Policy

The operations of the Chocolate Bayou Plant will not be regulated by the Alternative Emission Reduction Policy.

§ 101.24-27 Fees

INEOS will submit all appropriately assessed fees to the TCEQ.

§ 101.28 Stringency Determination for Federal Operating Permits

INEOS is not requesting a stringency determination at this time; therefore, this section does not apply.

§ 101.30 Conformity of General Federal Actions to State Implementation Plans

A conformity determination is not required under this section because this application is not a federal action, and increases in VOC and NO_X emissions are less than 50 tons per year and 100 tons per year, respectively.

§101.150-155 Voluntary Supplemental Leak Detection Program

INEOS will comply with the applicable requirements in these sections.

§ 101.201 Emission Event Reporting and Recordkeeping Requirements

INEOS will notify the appropriate air pollution control agencies and the Executive Director of any unauthorized emissions that exceed a reportable quantity (as defined in 30 TAC 101) within 24 hours of discovery as required.

§ 101.211 Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements

INEOS will notify the appropriate air pollution control agencies and the Executive Director in writing at least ten days prior to any scheduled maintenance, start-up, or shutdown which will or may cause emissions which exceed a reportable quantity.

§ 101.221-224 Operational Requirements, Demonstrations, and Actions to Reduce Excessive Emissions

INEOS will comply with the applicable requirements in these sections.

§ 101.231-233 Variances

These sections do not apply to this permit application.

§ 101.300-311 Emission Credit Banking and Trading

These sections do not apply to this permit application because INEOS is not requesting any emissions reductions.

§ 101.330-339 Emissions Banking and Trading Allowances

These sections do not apply to this permit application because INEOS is not requesting any emissions reductions.

§ 101.350-363 Mass Emissions Cap and Trade Program

INEOS will comply with all requirements in these sections.

§ 101.370-379 Discrete Emission Credit Banking and Trading

These sections do not apply to this permit application because INEOS is not requesting any emissions reductions.

§ 101.380-385 System Cap Trading

This permit application does not involve emission banking and trading; therefore, these sections do not apply.

§ 101.390-403 Highly-Reactive Volatile Organic Compound Emissions Cap and Trade Program

INEOS will comply with all applicable requirements of HRVOC.

§ 101.501-508 Clean Air Interstate Rule

These sections do not apply.

6.2 Chapter 111 | Control of Air Pollution from Visible Emissions and Particulate Matter

§ 111.111-113 Visible Emissions

Visible emissions from any source associated with this permit application will not exceed opacity limitations specified by these sections.

§ 111.121-129 Incineration

There are no incinerators associated with the Chocolate Bayou Plant.

§ 111.131-139 Abrasive Blasting of Water Storage Tanks Performed by Portable Operations

There are no activities associated with this permit application involving abrasive cleaning of water storage tanks by portable operations.

§ 111.141-149 Materials Handling, Construction, Roads, Streets, Alleys, and Parking Lots

This rule does not apply. The facility is located in Brazoria County, which is not included in the Geographic Areas of Application.

§ 111.151-153 Emissions Limits on Nonagricultural Processes

Particulate emissions occurring during normal operation will not exceed allowable emission rates or concentration levels established for each source.

§ 111.171-175 Emissions Limits on Agricultural Processes

There are no agricultural processes at the Chocolate Bayou Plant.

§ 111.181-183 Exemptions for Portable or Transient Operations

The Chocolate Bayou Plant is not a portable or transient operation.

§ 111.201-221 Outdoor Burning

This activity is not part of this permit application; therefore, these sections do not apply.

6.3 Chapter 112 | Control of Air Pollution from Sulfur Compounds

INEOS will comply with all applicable net ground-level concentrations specified in this chapter. The SO_2 net ground-level concentration will not exceed 0.28 ppmv averaged over any 30 minute period.

6.4 Chapter 113 | Control of Air Pollution from Toxic Chemicals

INEOS will operate in compliance with all applicable requirements of this section.

6.5 Chapter 114 | Control of Air Pollution from Motor Vehicles

INEOS will operate in compliance with the requirements of this regulation as implemented in the State of Texas.

6.6 Chapter 115 | Control of Air Pollution from Volatile Organic Compounds

§ 115.110-119 Storage of Volatile Organic Compounds

There are no VOC emissions from non-combustion related processes associated with this permit application; therefore, this regulation does not apply.

§ 115.120-129 Vent Gas Control

There are no VOC emissions from non-combustion related processes associated with this permit application; therefore, this regulation does not apply.

§ 115.131-139 Water Separation

There are no water separator processes associated with this permit application; therefore, this regulation does not apply.

§ 115.140-149 Industrial Wastewater

There are no industrial wastewater generating processes associated with this permit application; therefore, this regulation does not apply.

§ 115.152-159 Municipal Solid Waste Landfills

INEOS does not operate a municipal solid waste landfill at this site; therefore, these sections do not apply.

§ 115.160-169 Batch Processes

There is not an affected batch process associated with this permit application.

§ 115.211-219 Loading and Unloading of Volatile Organic Compounds

These sections do not apply because the proposed permit application does not involve gasoline or VOC loading and unloading nor does it involve the filling of gasoline storage vessels for motor vehicle fuel dispensing facilities.

§ 115.221-229 Filling of Gasoline Storage Vessels (Stage I) for Motor Vehicle Fuel Dispensing Facilities

There is no motor vehicle fueling associated with this permit application; therefore, these sections do not apply.

§ 115.234-239 Control of Volatile Organic Compound Leaks from Transport Vessels

Materials loaded into tank trucks at this facility have vapor pressures less than 0.5 psia; therefore, these sections do not apply.

§ 115.240-249 Control of Vehicle Refueling Emissions (Stage II) at Motor Vehicle Fuel Dispensing Facilities

There is no motor vehicle fueling associated with this permit application; therefore, these sections do not apply.

§ 115.252-259 Control of Reid Vapor Pressure of Gasoline

The Chocolate Bayou Plant is not located in the El Paso area; therefore, these sections do not apply.

§ 115.311-319 Process Unit Turnaround and Vacuum-Producing Systems in Petroleum Refineries

The Chocolate Bayou Plant is not a petroleum refinery; therefore, these sections do not apply.

§ 115.322-329 Fugitive Emission Control in Petroleum Refineries in Gregg, Nueces, and Victoria Counties

The Chocolate Bayou Plant is not a petroleum refinery and is not located in one of these counties; therefore, these sections do not apply.

§ 115.352-359 Fugitive Emission Control in Petroleum Refining, Natural Gas/Gasoline Processing, and Petrochemical Processes in Ozone Non-attainment Areas

INEOS will comply with all applicable emission control, testing, monitoring and recordkeeping requirements of these sections.

§ 115.412-419 Degreasing Processes

There is not a degreasing process associated with this permit application.

§ 115.420-429 Surface Coating Processes

There is no surface coating process associated with this permit application.

§ 115.430-439 Flexographic and Rotogravure Printing

These sections do not apply to this permit application.

§ 115.440-449 Offset Lithographic Printing

These sections do not apply to this permit application.

§ 115.510-519 Cutback Asphalt

These sections do not apply to this permit application.

§ 115.531-539 Pharmaceutical Manufacturing Facilities

These sections do not apply to this permit application.

§ 115.540-549 Degassing or Cleaning of Stationary, Marine, and Transport Vessels

INEOS will comply with all applicable requirements related to MSS activities related to degassing or cleaning of vessels.

§ 115.552-559 Petroleum Dry Cleaning Systems

These sections do not apply to this permit application.

§ 115.600-619 Consumer Products

The Chocolate Bayou Plant does not sell, supply, offer for sale, distribute, or manufacture consumer products as defined in this section; therefore, these sections do not apply.

§ 115.720-729 Vent Gas Control

INEOS will comply with any applicable requirements of these sections.

§ 115.760-769 Cooling Tower Exchange Systems

INEOS will comply with any applicable requirements of these sections.

§ 115.780-789 Fugitive Emissions

INEOS will comply with any applicable requirements of these sections.

§ 115.901-916 Alternate Means of Control

INEOS is not requesting an AMOC; therefore, these sections do not apply.

§ 115.920-923 Early Reductions

INEOS is not requesting an extension to comply with any requirements in this chapter; therefore, these sections do not apply.

§ 115.930-940 Compliance and Control Plan Requirements

A schedule for achieving compliance with the applicable sections of this regulation will be provided upon request by the Executive Director. Emissions reduction credits and discrete emissions reduction credits will not be used to meet the emission control requirements of this chapter.

§ 115.950 Emissions Trading

INEOS will not be obtaining any reduction credits for this permit application; therefore, these sections do not apply.

6.7 Chapter 116 | Control of Air Pollution by Permits for New Construction or Modification

§ 116.110 Applicability

This permit application is submitted by INEOS to the TCEQ in order to obtain the appropriate authorization for the new cracking furnace.

§ 116.111 General Application

(a)(1) INEOS will submit a completed Form PI-1 and supporting documentation to comply with this section.

(a)(2) The following items are discussed:

(A) **Protection of Public Health and Welfare**

Emissions from the facilities will comply with all rules and regulations of the TCEQ and with the intent of the Texas Clean Air Act, including protection of the health and physical property of the people.

(B) **Measurement of Emissions**

INEOS will make provisions for measuring the air contaminants from the facilities covered by this permit application as determined by the Executive Director of the TCEQ.

(C) **Best Available Control Technology (BACT)**

The facilities covered by this permit application will utilize BACT, with consideration given to technical practicability and economic reasonableness or reducing or eliminating emissions on a group of facilities basis. Please see Section 4 of this document for a detailed BACT discussion.

(D) **New Source Performance Standards (NSPS)**

INEOS will continue to comply with all applicable NSPS requirements.

(E) **National Emission Standards for Hazardous Air Pollutants (NESHAP)**

INEOS will continue to comply with all applicable NESHAP requirements.

(F) **NESHAP for Source Categories (MACT)**

INEOS will continue to comply with all applicable MACT standards NESHAP requirements.

(G) **Performance Demonstration**

The facilities covered by this permit application will achieve the performance standards represented in this application.

(H) **Nonattainment Review**

The Chocolate Bayou Plant is an existing major stationary source of VOC and NO_X in Brazoria County, a designated severe nonattainment area for ozone. Nonattainment Review requirements are discussion under Section 1.2 of this document.

(I) **Prevention of Significant Deterioration (PSD) Review**

The Chocolate Bayou Plant is located in Brazoria County, which is classified as nonattainment for ozone. The PSD regulations apply to the following pollutants: NO_X, SO_2, CO, CO_2, PM_{10}, and $PM_{2.5}$. PSD requirements are discussed in Section 1.2 of this document.

(J) **Air Dispersion Modeling**

INEOS will perform air dispersion modeling upon request by the TCEQ.

(K) **Hazardous Air Pollutants**

This permit application does not propose a reconstruction or construction of a major source of HAPs as described in Section 112(g) of the Federal Clean Air Act. These sections do not apply.

(L) **Mass Cap and Trade Allowances**

This permit application does not propose a change regarding Mass Cap and Trade allowances.

(b) INEOS will comply with all applicable requirements of Chapter 39 relating to Public Notice.

§ 116.112 Distance Limitations

INEOS will comply with all applicable distance limitation requirements set forth in this section.

§ 116.114 Applicable Review Schedule

INEOS will comply with all conditions of the TCEQ permit review schedule.

§ 116.115 General and Special Conditions

INEOS will comply with all applicable requirements set forth in this section and with all general and special conditions of the permit.

§ 116.116 Changes to Facilities

The Chocolate Bayou Plant will be operated in accordance with the representations made in this permit application and any ensuing applications. Changes in construction or operation resulting in changes in the method of controlling emissions, the character of the emissions, or an increase in emissions will be preceded by an appropriate authorization.

§ 116.117 Documentation and Notification of Changes to Qualified Facilities

INEOS is not claiming physical or operational modifications to a qualified facility under 30 TAC § 116.116(e).

§ 116.119 De Minimis Facilities or Sources

INEOS is not requesting consideration of this section in this permit application.

§ 116.120 Voiding of Permits

INEOS will comply with all applicable requirements of this section.

§ 116.127 Actual to Projected Actual and Emissions Exclusion Test for Emissions

INEOS will comply with all applicable requirements of this section when such projects necessitate such an action.

§ 116.130-137 Public Notification and Comment Procedures

INEOS will comply with all applicable requirements of this section for this permit application. See Section 1.7 for a detailed public notice discussion.

§ 116.140-143 Permit Fees

INEOS will comply with all applicable requirements of these sections for this permit application.

§ 116.150 New Major Source or Major Modification in Ozone Nonattainment Areas

The Chocolate Bayou Plant is an existing major stationary source of VOC and NO_X in Brazoria County, a designated severe ozone nonattainment area. Please refer to Section 1.2 of this document for further discussion.

§ 116.151 New Major Source or Major Modification in Nonattainment Areas Other than Ozone

The Chocolate Bayou Plant is located in Brazoria County, which is attainment for all pollutants other than ozone; therefore, this section does not apply.

§ 116.160-163 Prevention of Significant Deterioration (PSD) Review

The Chocolate Bayou Plant is located in Brazoria County, which is classified as nonattainment for ozone. The PSD regulations apply to the following pollutants: NO_X, SO_2, CO, CO_2, PM_{10}, and $PM_{2.5}$. PSD requirements are discussed in Section 1.2 of this document.

§ 116.170-176 Emission Reductions: Offsets

Emission offsets are not required for this permit application.

§ 116.178 Relocations and Changes of Location for Portable Facilities

The Chocolate Bayou Plant is not a portable or transient operation.

§116.180-198 Plant-wide Applicability Permits

INEOS is not applying for a plant-wide applicability permit with this permit application; therefore, these sections do not apply.

§ 116.310-315 Permit Renewals

The permit will be renewed according to the applicable renewal schedule.

§ 116.400-406 Hazardous Air Pollutants: Regulations Governing Constructed or Reconstructed Major Sources (FCAA, § 112[g], 40 CFR Part 63)

INEOS will comply with all applicable requirements of this section for this permit application.

§ 116.601-620 Standard Permits

These sections do not apply.

§ 116.710-765 Flexible Permits

These sections do not apply.

§ 116.770-870 Permits for Grandfathered Facilities

These sections do not apply.

§ 116.910-931 Electric Generating Facility Permits

These sections do not apply.

§ 116.1010-1070Multiple Plant Permits

These sections do not apply.

§ 116.1200 Emergency Orders

INEOS will apply for an emergency order in compliance with these rules if a catastrophic event occurs that necessitates such an action.

§ 116.1400-1428Permits for Specific Designated Facilities

The Chocolate Bayou Plant does not meet the criteria set forth in these sections; therefore, these sections do not apply.

§ 116.1500-1540Best Available Retrofit Technology (BART)

INEOS is not requesting consideration of these sections to this permit application; therefore, these sections do not apply.

6.8 Chapter 117 | Control of Air Pollution From Nitrogen Compounds

INEOS will comply with the applicable requirements of these sections.

30 TAC 117 governs NO_X emissions from the following types of facilities: Major Sources in an applicable Ozone Non-Attainment Area, acid manufacturers, and gas-fired combustion unit manufacturers, distributors, retailers, and installers. 30 TAC 117 also governs NO_X emissions from Minor Sources located in the Houston/Galveston ozone Non-Attainment Area and sources located in specified counties in Central and East Texas. The Plant will be located in Brazoria County which is part of the Houston/Galveston-Brazoria Area. INEOS will comply with the applicable rules of this section.

§117.100-156 Combustion Control: Beaumont-Port Arthur

This section does not apply as the Plant will not be within the geographic area of applicability.

§117.200-256 Combustion Control: Dallas-Fort Worth

This section does not apply as the Plant will not be within the geographic area of applicability.

§117.300-356 Combustion Control: Houston-Galveston-Brazoria

This section will apply. Per §117.303, the new source of combustion will comply with all the emission and operating limits specified under this subpart. Therefore, the Plant will comply with this rule.

§117.400-456 Combustion Control Dallas/Fort Worth 8-HR

This section does not apply as the Plant will not be within the geographic area of applicability

§117.1000-1056 Combustion Control at Major Utility Electric Generation Sources Beaumont-Port Arthur

This section does not apply as the Plant will not be within the geographic area of applicability.

§117.1100-1156 Combustion Control at Major Utility Electric Generation Sources Dallas-Fort Worth

This section does not apply as the Plant will not be within the geographic area of applicability.

§117.1200-1256 Combustion Control at Major Utility Electric Generation Sources Houston-Galveston-Brazoria

This section does not apply as the Plant will not be a Utility Electric Generation Source.

§117.1300-1356 Combustion Control at Major Utility Electric Generation Sources Dallas-Fort Worth 8-HR

This section does not apply as the Plant will not be within the geographic area of applicability.

§117.2000-2045 Combustion Control at Minor Sources

The Plant is a major source, and not a minor source. Therefore, this section of 30 TAC 117 does not apply

§117.3000-3056 Multi-Region Combustion Control

The Plant will be located in Brazoria County which is not within the geographic area of applicability. In addition, The Plant is not a cement kiln and does not have water heaters, small boilers or process heaters. Therefore, this section of 30 TAC 117 does not apply.

§117.4000-4050 Acid Manufacturing

The Plant is not an acid manufacturer. Therefore, this section of 30 TAC 117 does not apply.

§117.8000-8140 General Monitoring and Testing Requirements

The Plant will perform monitoring and testing as defined in these sections as a part of this permit application and will comply with these rules.

§117.9000-9300 Compliance Schedule

The Plant will follow the compliance schedule as defined in these sections as a part of this permit application.

6.9 Chapter 118 | Control of Air Pollution Episodes

In the event of an air pollution episode, INEOS will comply with any applicable order issued by the Executive Director.

6.10 Chapter 122 | Federal Operating Requirements

The Olefins Business Unit is covered by Federal Operating Permit No. O-2327. INEOS will comply with all applicable requirements of this chapter.

6.11 40 CFR 52.21(o) | Additional Impact Analysis

The PSD permitting rules require an analysis of the following.

(1) The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

> The proposed furnace will be constructed in an area of the INEOS property that is already developed. No disturbance to soils and vegetation will occur as part of construction and operation. The proposed furnace is being constructed to provide an incremental increase in production. General commercial, residential, industrial and other growth as a result of this incremental production increase will not be significant. As noted in the air dispersion modeling report prepared for this project (summarized in Table 5-4), emissions will be below the respective Significant Impact Level for all pollutants.

(2) The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.

> The proposed furnace is being constructed to provide an incremental increase in production. General commercial, residential, industrial and other growth as a result of this incremental production increase will not be significant. Therefore, there should not be any resulting emissions from these activities.

(3) Visibility monitoring. The Administrator may require monitoring of visibility in any Federal class I area near the proposed new stationary source for major modification for such purposes and by such means as the Administrator deems necessary and appropriate.

> The nearest Federal Class I Area is the Caney Creek Wilderness in Arkansas, which is approximately 600 km from the facility. The proposed particulate emissions are below the PSD

permitting trigger. The emissions from the proposed furance will not have an impact on this area.

Appendix A | Forms

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

Update: The TCEQ **requires** that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued by the TCEQ and no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to the TCEQ Web site at www.tceq.state.tx.us/permitting/central_registry/guidance.html.

I. APPLICANT INFORMATION				
A. Company or Other Legal Name: INEOS USA LLC				
Texas Secretary of State Charter/Registration Number (*if applicable*):				
B. Company Official Contact Name : Theresa Vitek				
Title: Manager, SHE Department				
Mailing Address: P.O. Box 1488				
City: Alvin	State: TX		ZIP Code: 77512-1488	
Telephone No: 281-581-3498	Fax No.: 281-581-3604		E-mail Address: theresa.vitek@ineos.com	
C. Technical Contact Name: Daniel Lutz				
Title: Environmental Compliance Advisor				
Company Name: INEOS USA LLC				
Mailing Address: P.O. Box 1488				
City: Alvin	State: TX		ZIP Code: 77512-1488	
Telephone No.: 713-373-9300	Fax No.: 281-581-3604		E-mail Address: Daniel.Lutz@ineos.com	
D. Facility Location Information:				
Street Address: 2 Miles south of intersection FM 2917 on FM 2004				
If no street address, provide clear driving directions to the site in writing:				
City: Alvin	County: Brazoria		ZIP Code: 77511	
E. TCEQ Account Identification Number (leave blank if new site or facility): BL-0002-S				
F. Is a TCEQ Core Data Form (TCEQ Form No. 10400) attached?				☐ YES ☒ NO
G. TCEQ Customer Reference Number *(leave blank if unknown)*: CN602817884				
H. TCEQ Regulated Entity Number *(leave blank if unknown)*: RN100238708				
II. IMPORTANT GENERAL INFORMATION				
A. Is confidential information submitted with this application?				☒ YES ☐ NO
If "YES," is each "confidential" page marked "**CONFIDENTIAL**" in large red letters?				☒ YES ☐ NO

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

TCEQ

II. IMPORTANT GENERAL INFORMATION ***(continued)***		
B. Is this application in response to a TCEQ investigation or enforcement action?		☐ YES ☒ NO
If "YES", attach a copy of any correspondence from the TCEQ		
C. Number of New Jobs: 0		
D. Names of the State Senator and district number for this facility site: Honorable Mike Jackson, District 11		
Names of State Representative and district number for this facility site: Honorable Dennis Bonnen, District 25		
E. For Concrete Batch Plants, and PSD, or Nonattainment Permits that require public notice, name of the County Judge for this facility site: Honorable Joe King		
Mailing Address: 111 East Locust Street		
City: Angleton	State: Texas	ZIP Code: 77515
F. For Concrete Batch Plants, is the facility located in a municipality or an extraterritorial jurisdiction of a municipality?		☐ YES ☐ NO
If "YES," list the name(s) of the Presiding Officer(s) for this facility site:		
Mailing Address:		
City:	State:	ZIP Code:
III. FACILITY AND SOURCE INFORMATION		
A. Site Name: Chocolate Bayou Plant		
B. Area Name/Type of Facility:		☒ Permanent ☐ Portable
C. Principal Company Product or Business: Olefins and Polymers Production		
Principal Standard Industrial Classification Code: 2869		
D. Projected Start of Construction Date: 07/01/2012	Projected Start of Operation Date: 10/01/2013	
IV. TYPE OF PERMIT ACTION REQUESTED		
A. Permit Number *(if existing)*:		
B. Is this an initial permit application?		☒ YES ☐ NO
If "YES," check the type of permit requested *(check all that apply)*: ☒ State Permit ☐ Flexible Permit ☐ Multiple Plant Permit ☐ Nonattainment Federal Permit ☐ Prevention of Significant Deterioration Federal Permit ☐ Hazardous Air Pollutants Permit Federal Clean Air Act § 112(g) Other: ______		

IV. TYPE OF PERMIT ACTION REQUESTED *(continued)*			
C. Is this a permit amendment?			☐ YES ☒ NO
Is this a permit revision?? (SB 1126 change)			☐ YES ☒ NO
If "YES," check the type of permit requested *(check __all__ that apply)*: ☐ State Permit Amendment ☐ Flexible Permit Amendment ☐ Multiple Plant Permit Amendment ☐ Nonattainment Major Modification ☐ Prevention of Significant Deterioration Major Modification ☐ Hazardous Air Pollutants Permit Federal Clean Air Act § 112(g) Modification Other:______			
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with Senate Bill 1673? [THSC 382.055(a)(2)](80th Legislative)			☐ YES ☒ NO
E. Is this application for a change of location of previously permitted facilities?			☐ YES ☒ NO
If "YES," answer IVE. 1. - IVE. 4.			
1. Current location of facility:			
Street Address *(If no street address, provide clear driving directions to the site in writing.)*:			
City:	County:	ZIP Code:	
2. Proposed location of facility:			
Street Address *(If no street address, provide clear driving directions to the site in writing.)*:			
City:	County:	ZIP Code:	
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions?			☐ YES ☐ NO
If "NO," attach detailed information.			
4. Is the site where the facility is moving considered major?			☐ YES ☐ NO
F. Is this a relocation?			☐ YES ☒ NO
G. Are there any standard permits, exemptions or permits by rule to be consolidated into this permit?			☐ YES ☒ NO

IV. TYPE OF PERMIT ACTION REQUESTED ***(continued)***	
H. Are you permitting a facility or group of facilities that have planned maintenance, startup and shutdown emissions that cannot be authorized by a permit by rule or standard permit or that are authorized by a permit by rule or standard permit and are being rolled into this permit?	☐ YES ☒ NO
If "YES," attach information on any changes to emissions under this application as specified in Sections IX, and X.	
If "YES," answer IVH. 1 -IVH. 3.	
1. Are the activities to be included in this permit covered by any previously existing MSS authorizations?	☐ YES ☒ NO
If "YES," provide a listing of all other authorizations (permit by rule or standard permit and the associated registration number if any).	
2. Have the emissions been previously submitted as part of an emissions inventory?	☐ YES ☒ NO
3. List which years the MSS activities were included in emissions inventory submittals:	
I. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability)	
Is this facility located at a site required to obtain a federal operating permit under 30 TAC Chapter 122?	☒ YES ☐ NO
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this PI-1 application is approved. ☒ FOP Significant Revision ☐ FOP Minor ☐ Application for an FOP Revision ☐ Operational Flexibility/Off-Permit Notification ☐ Streamlined Revision for GOP ☐ To be determined ☐ None	
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site (check all that apply)	
☐ GOP Issued ☐ GOP application/revision application: submitted or under APD review ☒ SOP Issued ☐ SOP application/revision application: submitted or under APD review	
V. PERMIT FEE INFORMATION	
A. Fee paid for this application:	$ 75,000.00
1. Is a copy of the check or money order attached to the original submittal of this application?	☒ YES ☐ NO ☐ N/A
2. Is a Table 30 entitled, "Certification of estimated Capital Cost and Fee Verification," attached?	☒ YES ☐ NO ☐ N/A

VI. PUBLIC NOTICE APPLICABILITY	
A. Is this a new permit application or a change of location application?	☒ YES ☐ NO
B. Is this an application for a major modification of a PSD, NA or 30 TAC § 112(g) permit?	☐ YES ☒ NO
C. Is this a state permit amendment application?	☐ YES ☒ NO
If "YES," answer VIC. 1. - VIC. 3.	
1. Is there any change in character of emissions in this application?	☐ YES ☒ NO
Is there a new air contaminant in this application?	☐ YES ☒ NO
2. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☒ NO
3. List the total annual emission increases associated with the application (*list <u>all</u> that apply*):	
Volatile Organic Compounds (VOC):	20.41 tpy
Sulfur Dioxide (SO_2):	1.49 tpy
Carbon Monoxide (CO):	97.88 tpy
Hazardous Air Pollutants (HAPs):	tpy
Nitrogen Oxides (NO_x):	21.68 tpy
Particulate Matter (PM):	13.07 tpy
PM_{10}:	10.32 tpy
$PM_{2.5}$:	5.88 tpy
Lead (Pb):	tpy
Other air contaminants not listed above: Hydrogen Sulfide (H2S)	0.02 tpy
Other air contaminants not listed above: Ammonia (NH3)	10.55 tpy

VII. PUBLIC NOTICE INFORMATION ***(complete if applicable)***		
A. Responsible Person:		
Name (☐ Mr. ☒Mrs. ☐Ms. ☐Dr.): Theresa Vitek		
Title: Manager, SHE Department		
Mailing Address: P.O. Box 1488		
City: Alvin	State: TX	ZIP Code: 77512-1488
Telephone No.: 281-581-3498	Fax No.: 281-581-3604	E-mail Address: theresa.vitek@ineos.com

VII. PUBLIC NOTICE INFORMATION *(complete if applicable)*		
B. Technical Contact:		
Company Name : INEOS USA LLC		
Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): Daniel Lutz		
Title: Environmental Compliance Advisor		
Mailing Address: P.O. Box 1488		
City: Alvin	State: TX	ZIP Code: 77512-1488
Telephone No.: 713-373-9300	Fax No.: 281-581-3604	E-mail Address: Daniel.Lutz@ineos.com
C. Application in Public Place:		
Name of Public Place: Alvin Library		
Physical Address: 105 South Gordon		
City: Alvin	County: Brazoria	
The public place has granted authorization to place the application for public viewing and copying?	☒ YES ☐ NO	
The public place has internet access available for the public?	☒ YES ☐ NO ☐ N/A	
Complete VII.D. 1. - VII.D. 3., as applicable.		
D.1. Name of the Mayor for this facility site:		
Gary Appelt		
Mailing Address: 216 W Sealy St		
City: Alvin	State: TX	ZIP Code: 77511
D.2. Name of the Federal Land Manager for this facility site:		
Mailing Address:		
City:	State:	ZIP Code:
D.3. Name of the Indian Governing Body for this facility site:		
Mailing Address:		
City:	State:	ZIP Code:

Texas Commission on Environmental Quality
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VII. PUBLIC NOTICE INFORMATION ***(complete if applicable)***	
E. Is a bilingual program **required** by the Texas Education Code in the School District?	☐ YES ☒ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?	☐ YES ☒ NO
If "YES," which language is **required** by the bilingual program?	
VIII. SMALL BUSINESS CLASSIFICATION ***(required)***	
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?	☐ YES ☒ NO
B. Is the site a major source under 30 TAC Chapter 122, Federal Operating Permit Program?	☒ YES ☐ NO
C. Are the site emissions of any individual air contaminant greater than 50 tpy?	☒ YES ☐ NO
D. Are the site emissions of all air contaminants combined greater than 75 tpy?	☒ YES ☐ NO

IX. TECHNICAL INFORMATION				
A. Is a current area map attached?				☒ YES ☐ NO
Are any schools located within 3,000 feet of this facility?				☐ YES ☒ NO
B. Is a plot plan of the plant property attached?				☒ YES ☐ NO
C. Is a process flow diagram and a process description attached?				☒ YES ☐ NO
D. Maximum Operating Schedule:	Hours: 24	Day(s): 7	Week(s): 52	Year(s):
Seasonal Operation?				☐ YES ☒ NO
If "YES," please describe.				
E. Are worst-case emissions data and calculations attached?				☒ YES ☐ NO
1. Is a Table 1(a) entitled, "Emission Point Summary Table," attached?				☒ YES ☐ NO
2. Is a Table 2 entitled, "Material Balance Table," attached?				☒ YES ☐ NO
3. Are equipment, process, or control device tables attached?				☒ YES ☐ NO
F. Are actual emissions for the last two years (determination federal applicability) attached?				☒ YES ☐ NO

Texas Commission on Environmental Quality
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TCEQ

X.	**STATE REGULATORY REQUIREMENTS** *Applicants must be in compliance with all applicable state regulations to obtain a permit or amendment.*	
A.	The emissions from the proposed facility will comply with all rules and regulations of the TCEQ and details are attached?	☒ YES ☐ NO
B.	The proposed facility will be able to measure emissions of significant air contaminants and details are attached?	☒ YES ☐ NO
C.	A demonstration of Best Available Control Technology (BACT) is attached?	☒ YES ☐ NO
D.	The proposed facilities will achieve the performance in the permit application and compliance demonstration or record keeping information is attached?	☒ YES ☐ NO
E.	Is atmospheric dispersion modeling attached?	☐ YES ☒ NO
F.	Does this application involve any air contaminants for which a "disaster review" is required?	☐ YES ☒ NO
	If "YES," details must be attached.	
	Note: For a list of air contaminants for which a "disaster review" will be required, refer to the NSRPD Disaster Review Guidance Document at www.tceq.state.tx.us/permitting/air/rules/federal/63/63hmpg.html.	
G.	Is this facility or group of facilities located at a site within an Air Pollutant Watch List (APWL) area?	☐ YES ☒ NO
	If "YES," answer X.G. 1. - X.G. 3.	
1.	List the APWL Site Number:	
2.	Does the site emit a pollutant of concern for the APWL area in which the site is located?	☐ YES ☐ NO
3.	If "YES," list the pollutant(s) of concern emitted by this site:	
H.	Is this facility or group of facilities located at a site within the Houston/Galveston nonattainment area? (Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, or Waller Counties)	☒ YES ☐ NO
	If "YES," answer X.H. 1. - X.H. 4.	
1.	Does the facility or group of facilities located at this site have an uncontrolled design capacity to emit 10 tpy or more of NO_X?	☒ YES ☐ NO
2.	Is this site subject to 30 TAC Chapter 101, Subchapter H, Division 3 (Mass Emissions Cap and Trade)?	☒ YES ☐ NO
3.	Does this action make the site subject to 30 TAC Chapter 101, Subchapter H, Division 3 (Mass Emissions Cap and Trade)?	☐ YES ☒ NO
4.	Does this action require the site to obtain additional emission allowances?	☐ YES ☒ NO

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XI. FEDERAL REGULATORY REQUIREMENTS **Applicants must be in compliance with all applicable federal regulations to obtain a permit or amendment**. ***If any of the following questions are answered "YES, the application must contain detailed attachments addressing applicability, identify federal regulation Subparts, show how requirements are met, and include compliance information.***	
A. Does a Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?	☒ YES ☐ NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?	☒ YES ☐ NO
C. Does a 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D. Does nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E. Does prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F. Does Hazardous Air Pollutant Major Source [FAA § 112(g)] requirements apply to this application?	☐ YES ☒ NO
XII. COPIES OF THIS APPLICATION	
A. Has the required fee been sent separately with a copy of this Form PI-1 to the TCEQ Revenue Section? *(MC 214, P.O. Box 13088, Austin, Texas 78711).*	☒ YES ☐ NO ☐ N/A
B. Are the Core Data Form, Form PI-1, and all attachments being sent to the TCEQ in Austin?	☒ YES ☐ NO
OPTIONAL: Has an extra copy of the Core Data Form, Form PI-1 and all attachments been sent to the TCEQ in Austin?	☐ YES ☒ NO
If "YES," please mark this application as "COPY."	
C. Is a copy of the Core Data Form, the Form PI-1, and all attachments being sent to the appropriate TCEQ regional office?	☒ YES ☐ NO
D. Is a copy of the Core Data Form, the Form PI-1, and all attachments being sent to each appropriate local air pollution control program(s)?	☒ YES ☐ NO
List all local air pollution control program(s):	
E. Is a copy of the Core Data Form, Form PI-1, and all attachments (without confidential information) being sent to the EPA Region 6 office in Dallas, Texas? (federal applications only)	☒ YES ☐ NO
F. This facility is located within 100 kilometers of the Rio Grande River and a copy of the application was sent to the International Boundary and Water Commission (IBWC):	☐ YES ☒ NO
G. This facility is located within 100 kilometers of a federally-designated Class I area and a copy of the application was sent to the appropriate Federal Land Manager:	☐ YES ☒ NO

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XIII. PROFESSIONAL ENGINEER (P.E.) SEAL	
Is the estimated capital cost of the project greater than $2 million dollars?	☒ YES ☐ NO
If "YES," the application must be submitted under the seal of a Texas licensed Professional Engineer (P.E.).	
XIV. DELINQUENT FEES AND PENALTIES	
Notice: This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the "Delinquent Fee and Penalty Protocol." For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.state.tx.us/agency/delin/index.html.	
XV. SIGNATURE	
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA. I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. I further state that I have read and understand TWC §§ 7.177-7.183, which defines CRIMINAL OFFENSES for certain violations, including intentionally or knowingly making or causing to be made false material statements or representations in this application, and TWC § 7.187, pertaining to CRIMINAL PENALTIES.	
NAME: Theresa Vitek, Manager, SHE Department	
SIGNATURE: Theresa Vitek *Original Signature Required*	
DATE: 4/25/2012	

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	February 2012	**Permit No.:**	NA	**Regulated Entity No.:**	100238708
Area Name:	No. 2 Olefins Unit			**Customer Reference No.:**	602817884

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

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
EPN (A)	**FIN (B)**	**NAME (C)**		**Pounds per Hour (A)**	**TPY (B)**
DDB-105	DDB-105	Furnace No. 105	NO_X	14.85	21.68
			CO	21.78	95.40
			VOC	3.72	16.28
			SO_2	0.41	1.78
			NH_3	4.77	10.45
			PM	2.97	13.02
			PM_{10}	2.35	10.29
			$PM_{2.5}$	1.34	5.86
			CO_2	59,919.95	214,504.88
			N_2O	1.49	6.51
			CH_4	1.55	6.81
			CO_2e	60,413.51	216,666.65
FUG-ADDF	FUG-ADDF	Furnace No. 105 Hydrocarbon Fugitives	VOC	0.94	4.12
			CH_4	0.27	1.19
			CO_2e	5.70	24.96
FUG-SCR2	FUG-SCR2	Furnace No. 105 Ammonia Fugitives	NH_3	0.02	0.10
DDF-106	DDF-106	Furnace No. 105 Decoke Cyclone	CO	103.46	2.48
			VOC	0.09	0.01
			PM	2.29	0.05
			PM_{10}	1.35	0.03
			$PM_{2.5}$	0.84	0.02
			CO_2	3,630.95	87.14

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	February 2012	Permit No.:	NA	Regulated Entity No.:	100238708
Area Name:	No. 2 Olefins Unit			Customer Reference No.:	602817884

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

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building	6. Height	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	NAME (C)	Zone	East (Meters)	North (Meters)	Height (Feet)	Above Ground (Feet)	Diameter (Feet) (A)	Velocity (fps) (B)	Temperature (°F) (C)	Length (Feet) (A)	Width (Feet) (B)	Axis Degrees (C)
DDB-105	DDB-105	Furnace No. 105	15	286,473.18	3,235,408.88		161.0	6.0	76.5	300			
FUG-ADDF	FUG-ADDF	Furnace No. 105 Hydrocarbon Fugitives	15	286,473.18	3,235,408.88		3.3				300	300	47
FUG-SCR2	FUG-SCR2	Furnace No. 105 Ammonia Fugitives	15	286,473.18	3,235,408.88		3.3				544	358	47
DDF-106	DDF-106	Furnace No. 105 Decoke Cyclone	15	286,473.18	3,235,408.88		125.0	2.5	60.0	600			

EPN = Emission Point Number
FIN = Facility Identification Number

TABLE 2

MATERIAL BALANCE

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

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate (lbs/hr orSCFM) standard conditions: 70°F 14.7 PSIA. Check appropriate column at right for each process.	Measurement	Estimation	Calculation
1. Raw Materials - Input Natural Gas Fuel Gas		8000 scfm 110,000 lbs/hr		X	
2. Fuels - Input					
3. Products & By-Products - Output Ethylene		248,000 tons/hr		X	
4. Solid Wastes - Output					
5. Liquid Wastes - Output					
6. Airborne Waste (Solid) - Output See Table 1(a)		See Table 1(a)			X
7. Airborne Wastes (Gaseous) - Output					

TABLE 6

BOILERS AND HEATERS

Type of Device: Furnace	Manufacturer: TBD
Number from flow diagram: DDB-105	Model Number:

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Fuel Gas	Hydrogen (30-40%) Ehylene (0-2%) Methane (balance)		Average 11,270 scfm	Design Maximum
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 732 Btu/scf	Average _____ scfm* ___% excess (vol)	Design Maximum ______ scfm * ______% excess (vol)

HEAT TRANSFER MEDIUM

Type Transfer Medium	Temperature°F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Design Maxim

OPERATING CHARACTERISTICS

Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp°F	scfm

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	See emissions calculations.

Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.

Also supply an assembly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit.Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F,14.7 psia

TABLE 10

CYCLONE SEPARATORS

Point Number (from Flow Diagram)	Manufacturer & Model No. (if available)
DDF-106	
Name of Abatement Device	**Type of Particulate Controlled**
Furnace No. 105 Decoke Cyclone	Coke Fines

GAS STREAM CHARACTERISTICS

Flow Rate (acfm)		Gas Stream Temperature(°F)	Particulate Grain Loading (grain/scf)	
Design Maximum	Average Expected		Inlet	Outlet
	100,000	600-750	0.9	0.09

PARTICULATE DISTRIBUTION
(By Weight)

Micron Range	Inlet	Outlet
0.0-1.0	0.09 %	39.90 %
1.0-3.0	0.18 %	7.98 %
3.0-5.0	0.18 %	7.98 %
5-10	0.55 %	0.24 %
10-20	3.90 %	1.73 %
over 20	95.10 %	42.16 %

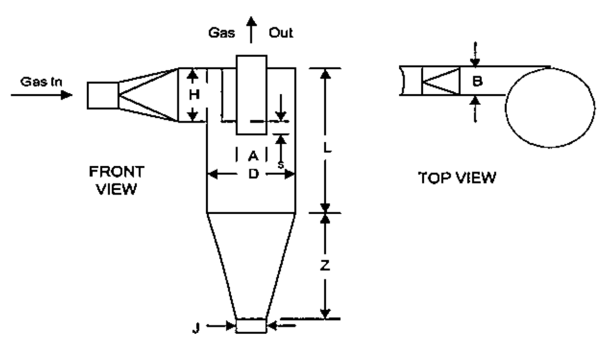
CYCLONE CHARACTERISTICS

Type of Cyclone (check appropriate boxes):

- ☐ wet
- ☑ dry
- ☐ single
- ☐ dual
- ☑ quadruple
- ☐ multiclone

Give Dimensions of Cyclone (See sample sketch):

1. B ___ in.	5. Z ___ in.
2. H ___ in.	6. D ___ in.
3. S ___ in.	7. A ___ in.
4. L ___ in.	8. J ___ in.



Method of Removal of Particulate from
from Cyclone Manual Unloading

Pressure drop through cyclone (inches water) ____________

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation

B. An assembly drawing (Front and Top View) of the abatement device dimensioned and to scale clearly showing the design, size and shape.

If the device has bypasses, safety valves, etc., include in drawing and specify when such bypasses are to be used and under what conditions.

Texas Commission on Environmental Quality
Table 30
Estimated Capital Cost and Fee Verification

Include estimated cost of the equipment and services that would normally be capitalized according to standard and generally accepted corporate financing and accounting procedures. Tables, checklists, and guidance documents pertaining to air quality permits are available from the Texas Commission on Environmental Quality, Air Permits Division Web site at **www.tceq.state.tx.us/nav/permits/air_permits.html**.

I. DIRECT COSTS [30 TAC § 116.141(c)(1)]	**Estimated Capital Cost**
A. A process and control equipment not previously owned by the applicant and not currently authorized under this chapter	$ >25MM
B. Auxiliary equipment, including exhaust hoods, ducting, fans, pumps, piping, conveyors, stacks, storage tanks, waste disposal facilities, and air pollution control equipment specifically needed to meet permit and regulation requirements	$ 0.00
C. Freight charges	$ 0.00
D. Site preparation, including demolition, construction of fences, outdoor lighting, road and parking areas	$ 0.00
E. Installation, including foundations, erection of supporting structures, enclosures or weather protection, insulation and painting, utilities and connections, process integration, and process control equipment	$ 0.00
F. Auxiliary buildings, including materials storage, employee facilities, and changes to existing structures	$ 0.00
G. Ambient air monitoring network	$ 0.00
II. INDIRECT COSTS [30 TAC § 116.141(c)(2)]	**Estimated Capital Cost**
A. Final engineering design and supervision, and administrative overhead	$ 0.00
B. Construction expense, including construction liaison, securing local building permits, insurance, temporary construction facilities, and construction clean-up	$ 0.00
C. Contractor's fee and overhead	$ 0.00
TOTAL ESTIMATED CAPITAL COST	$ >25MM

I certify that the total estimated capital cost of the project as defined in 30 TAC § 116.141 is equal to or less than the above figure. I further state that I have read and understand Texas Water Code § 7.179, which defines CRIMINAL OFFENSES for certain violations, including intentionally or knowingly making, or causing to be made, false material statements or representations.

Company Name: INEOS USA LLC

Company Representative Name (please print): Theresa Vitek Title: SHE Manager

Company Representative Signature: Theresa Vitek

Estimated Capital Cost		**Permit Application Fee**	**PSD/Nonattainment Application Fee**
Less than	**$300,000**	**$900 (minimum fee)**	**$3,000 (minimum fee)**
$300,000 to	**$25,000,000**	**0.30% of capital cost**	
$300,000 to	**$7,500,000**		**1.0% of capital cost**
Greater than	**$25,000,000**	**$75,000 (maximum fee)**	
Greater than	**$7,500,000**		**$75,000 (maximum fee)**

PERMIT APPLICATION FEE (from table above) = $ 75,000.00 Date: 7/28/11

Print Form Reset Form

TEXAS COMMISSION ON ENVIRONMENTAL
QUALITY
PO Box 13088
AUSTIN TX 78711-3088

Your Vendor Number is 80257556

Document	Your document	Date	Deductions	Gross amount
1900001934	TCEQ10196	06/27/2011	0.00	75,000.00
SEND CK TO DAN LUTZ@ SHE-MARINA VIEW				
Sum total			(0.00)	75,000.00

Inquiries concerning this payment should be directed to our office. Please call (800) 924-5598 or email to IneosAPDept@ineos.com.

In order to affect timely invoice payments please place your vendor P.O. or paykey number on all future invoices. Your vendor number is 80257556.

INEOS Olefins and Polymers USA
A Division of Ineos USA LLC
2600 South Shore Blvd. Suite 500
Attn: Accounts Payable
League City, TX 77573

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To The Order Of
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PER: Todd M. [illegible]
PER: Blaine Peck

Security features included. Details on back.

⑈4000211051⑈ ⑆031100209⑆ 38700694⑈

Professional Engineer Certification

I, Shauna R. Dallmer, a registered professional engineer in the State of Texas (Registration No. 97052), hereby certify that this document was reviewed by me or by others under my direct supervision. In preparing this document, reliance was placed upon information provided by INEOS USA L.L.C.

Shauna R. Dallmer
Name of Professional Engineer

Shauna R. Dallmer
Signature

97052
Registration Number

Texas
State

July 27, 2011
Date

Seal

TITAN Engineering, Inc.
P.E. Firm No. F-001835
2225 CR 90 Suite 105
Pearland, Texas 77584

Appendix B | Emission Calculations

INEOS USA LLC
CHOCOLATE BAYOU PLANT
INITIAL PERMIT APPLICATION
FURNACE EMISSIONS (EPN: DDB-105)

Emissions Basis

The proposed furnace will have the capability to be fueled with either natural gas or fuel gas from a variety of sources. NO_x and CO emissions are based on vendor guarantees. The maximum allowable (hourly) emissions for the permit allowable are based on the operating scenario that would result in the highest emissions, which is the combustion of fuel gas. The annual average emissions are also based on the combustion of fuel gas. The fuel gas composition will contain mostly methane, 1 -2% other materials, and hydrogen (averaging up to 40% by volume) for fuel gas. The hourly and annual emissions, including GHG (N_2O and CH_4), calculations are based on natural gas emission factors in AP-42, Chapter 1.4, adjusted for the heating value of fuel gas. The particulate size distribution from AP-42, Appendix B.2, Table B:2-2 was used to estimate the PM_{10} and $PM_{2.5}$ emission factors. Category 2 covers boilers firing a mixture of fuels, regardless of the fuel combination. Category 2 for combustion of mixed fuels has a 79% distribution for PM_{10} and 45% for $PM_{2.5}$ which was applied to the natural

Max Hourly Heat Input:	495	MMBtu/hr	*Design Capacity*			
Fuel Gas HHV:	732	Btu/scf	*Based on Dedicated Fuel Gas*	Fuel Gas HHV	995.09 Btu/scf	*Based on Natural Gas*
Volume of feed (Fdstk)	0.50	MMscf/hr	*Based on Natural Gas*			
Average Carbon Content (CC) :	0.71	lb C/lb fuel	*Based on Natural Gas*			
Molecular Weight (MW) :	17.99	lb/lb-mol	*Based on Natural Gas*			
Molar Volume Conversion Factor (M'	386.1	scf/lb-mol				
Hourly NO_x Factor:	0.03	lb/MMBtu	*Vendor Specifications*			
Annual NO_x Factor:	0.01	lb/MMBtu	*Vendor Specifications*			
CO Factor:	0.044	lb/MMBtu	*Vendor Specifications*			
VOC Factor:	5.5	lb/MMscf	*AP-42, Chapter 1.4, Table 1.4-2*			
PM Factor:	4.4	lb/MMscf	*Stack testing data on previous like-kind sources at site*			
PM10 Factor:	3.5	lb/MMscf	*stack testing data & AP-42, Appendix B.2: Generalized Particle Size Distributions, Table B:2-2, Category: 2, Combustion, Mixed Fuels*			
PM2.5 Factor:	2.0	lb/MMscf	*stack testing data & AP-42, Appendix B.2: Generalized Particle Size Distributions, Table B:2-2, Category: 2, Combustion, Mixed Fuels*			
SO_2 Factor:	0.6	lb/MMscf	*AP-42, Chapter 1.4, Table 1.4-2*			
Calculated CO_2 Factor	121.1	lb/MMscf				
CH_4 Factor:	2.3	lb/MMscf	*AP-42, Chapter 1.4, Table 1.4-2*			
N_2O Factor:	2.2	lb/MMscf	*AP-42, Chapter 1.4, Table 1.4-2*			

Emissions Summary

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
NO_x	14.85	21.68
CO	21.78	95.40
VOC	3.72	16.28
SO_2	0.41	1.78
PM	2.97	13.02
PM_{10}	2.35	10.29
$PM_{2.5}$	1.34	5.86
CO_2	59,919.95	214,504.88
CO_2 e	60,413.51	216,666.65
CH_4	1.55	6.81
N_2O	1.49	6.51

Total CO_2 e based on Global Warming Potential for CO_2, CH_4 and N_2O found on Part 98's Table A–1 . [CO_2 e]= [CO_2] + [CH_4 x 21] + [N_2O x 310]

NO_x Emissions

$$0.03 \frac{lb\ NO_x}{MMBtu} * 495 \frac{MMBtu}{hr} = \boxed{14.85 \frac{lb\ NO_x}{hr}}$$

$$0.01 \frac{lb\ NO_x}{MMBtu} * 495 \frac{MMBtu}{hr} * 8{,}760 \frac{hr}{yr} * \frac{1}{2{,}000} \frac{ton}{lb} = \boxed{21.68 \frac{ton\ NO_x}{yr}}$$

CO Emissions

$$0.044 \frac{lb\ CO}{MMBtu} * 495 \frac{MMBtu}{hr} = \boxed{21.78 \frac{lb\ CO}{hr}}$$

$$0.044 \frac{lb\ CO}{MMBtu} * 495 \frac{MMBtu}{hr} * 8{,}760 \frac{hr}{yr} * \frac{1}{2{,}000} \frac{ton}{lb} = \boxed{95.40 \frac{ton\ CO}{yr}}$$

INEOS USA LLC
CHOCOLATE BAYOU PLANT
INITIAL PERMIT APPLICATION
FURNACE EMISSIONS (EPN: DDB-105)

CO_2 Emissions

CO_2 = (44/12) * F_{dstk} * CC * (MW/MVC) * 0.001 *(metric units)*
CO_2 = (44/12) * F_{dstk} * CC * (MW/MVC) * 0.0005 *(english units)*

44	MW CO_2	*	0.50	MMscf	*	1,000,000	scf	*	0.71	lb C	*		
12	MW C			hr			MMscf			lb fuel			
17.99	lb	*	1	scf							=	59,920	lb CO_2
	lb-mol		386	lb-mol									hr
44	MW CO_2	*	0.64	MMscf	*	1,000,000	scf	*	8760	hr	*		
12	MW C			hr			MMscf			yr			
0.71	lb C	*	11.34	lb	*	1	scf	*	1	ton	=	214,504.88	ton CO_2
	lb fuel			lb-mol		386	lb-mol		2000	lb			yr

VOC Emissions

5.5	lb VOC	*	495	MMBtu	*	1	scf							=	3.72	lb VOC
	MMscf			hr		732	Btu									hr
5.5	lb VOC	*	495	MMBtu	*	8,760	hr	*	1	ton	*	1	scf	=	16.28	ton VOC
	MMscf			hr			yr		2,000	lb		732	Btu			yr

PM Emissions

4.4	lb PM	*	495	MMBtu	*	1	scf							=	2.97	lb PM
	MMscf			hr		732	Btu									hr
4.4	lb PM	*	495	MMBtu	*	8,760	hr	*	1	ton	*	1	scf	=	13.02	ton PM
	MMscf			hr			yr		2,000	lb		732	Btu			yr

PM_{10} Emissions

3.5	lb PM_{10}	*	495	MMBtu	*	1	scf							=	2.35	lb PM_{10}
	MMscf			hr		732	Btu									hr
3.5	lb PM_{10}	*	495	MMBtu	*	8,760	hr	*	1	ton	*	1	scf	=	10.29	ton PM_{10}
	MMscf			hr			yr		2,000	lb		732	Btu			yr

$PM_{2.5}$ Emissions

2.0	lb $PM_{2.5}$	*	495	MMBtu	*	1	scf							=	1.34	lb $PM_{2.5}$
	MMscf			hr		732	Btu									hr
2.0	lb $PM_{2.5}$	*	495	MMBtu	*	8,760	hr	*	1	ton	*	1	scf	=	5.86	ton $PM_{2.5}$
	MMscf			hr			yr		2,000	lb		732	Btu			yr

SO_2 Emissions

0.6	lb SO_2	*	495	MMBtu	*	1	scf							=	0.41	lb SO_2
	MMscf			hr		732	Btu									hr
0.6	lb SO_2	*	495	MMBtu	*	8,760	hr	*	1	ton	*	1	scf	=	1.78	ton SO_2
	MMscf			hr			yr		2,000	lb		732	Btu			yr

CH_4 Emissions

2.3	lb CH_4	*	495	MMBtu	*	1	scf							=	1.55	lb CH_4
	MMscf			hr		732	Btu									hr
2.3	lb CH_4	*	495	MMBtu	*	8,760	hr	*	1	ton	*	1	scf	=	6.81	ton CH_4
	MMscf			hr			yr		2,000	lb		732	Btu			yr

N_2O Emissions

2.2	lb N_2O	*	495	MMBtu	*	1	scf							=	1.49	lb N_2O
	MMscf			hr		732	Btu									hr
2.2	lb N_2O	*	495	MMBtu	*	8,760	hr	*	1	ton	*	1	scf	=	6.51	ton N_2O
	MMscf			hr			yr		2,000	lb		732	Btu			yr

INEOS USA LLC
CHOCOLATE BAYOU PLANT
INITIAL PERMIT APPLICATION
FURNACE EMISSIONS (EPN: DDB-105) FUEL ANALYSIS

Natural Gas Fuel Analysis

Chemical		MW	atoms C/mol	HHV Btu/lb	sample 1	sample 2	average mol frac.	MW	HHV Btu/SCF	CC lb/lb fuel
Methane	CH4	16	1	23861	86.11	94.69	0.908	14.52	900	0.6056
Ethane	C2H6	30	2	22304	6.28	1.99	0.041	1.24	72	0.0553
Propane	C3H8	44	3	21646	0.77	0.26	0.005	0.23	13	0.0103
Butane	C4H10	58	4	21490	0.36	0.12	0.002	0.14	8	0.0064
Pentane	C5H12	72	5	21072	0.09	0.03	0.001	0.04	2	0.0020
Nitrogen	N2	28	0	0	0.45	0.32	0.004	0.11	0	0.0000
Carbon Dioxide	CO2	44	1	0	5.87	1.79	0.038	1.69	0	0.0256
Oxygen	O2	32	0	0	0.08	0	0.000	0.01	0	0.0000
					100.01	99.2	1	17.99	995.09	0.71

HHV, Btu/lb 21300

INEOS Fuel Gas Analysis

Chemical		MW	atoms C/mol	HHV Btu/lb	average	max	average mol frac.	MW	HHV Btu/SCF	CC lb/lb fuel
Methane	CH4	16	1	23861	63	63	0.630	10.08	625	0.6667
Ethylene	C2H4	28	2	21884	2	2	0.020	0.56	32	0.0423
Hydrogen	H2	2	0	61084	35	35	0.350	0.70	111	0.0000
					100	100	1	11.34	767.62	0.71

HHV, Btu/lb 26061

INEOS USA LLC
CHOCOLATE BAYOU PLANT
INITIAL PERMIT APPLICATION
FUGITIVE EMISSIONS (EPN: FUG-ADDF)

EQUIPMENT TYPE	SERVICE	VOC	COUNT	EMISSION FACTOR	REDUCTION CREDIT	VOC EMISSIONS	
				(lb/hr/source)[2]	(%)[1]	(lb/hr)	(tpy)
			a	b	c	d	e
Valves	Gas/Vapor	With Ethylene	74	0.0258	97	0.06	0.25
		Average		0.0132			
		Without Ethylene		0.0089			
	Light Liquid	With Ethylene	3	0.0459	97	0.00	0.02
		Average		0.0089			
		Without Ethylene		0.0035			
	Heavy Liquid	With Ethylene		0.0005			
		Average		0.0005			
		Without Ethylene		0.0007			
Pump Seals	Light Liquid	With Ethylene		0.1440			
		Average		0.0439			
		Without Ethylene		0.0386			
	Heavy Liquid	With Ethylene		0.0046			
		Average		0.0190			
		Without Ethylene		0.0161			
Flanges/Connectors	Gas/Vapor	With Ethylene	231	0.0053	30	0.86	3.75
		Average		0.0039			
		Without Ethylene		0.0029			
	Light Liquid	With Ethylene	6	0.0052	30	0.02	0.10
		Average		0.0005			
		Without Ethylene		0.0005			
	Heavy Liquid	All		0.00007			
Compressor Seals	All	All		0.5027			
Relief Valves	All	All		0.2293			
Open Ended Lines	All	With Ethylene		0.0075			
		Average		0.0038			
		Without Ethylene		0.004			
Sampling Connections	All	All		0.033			
Total			**314**		**Total**	**0.94**	**4.12**

Notes:

1. Reduction credit based on TCEQ - 28 VHP monitoring program.
2. Emissions were calculated using the applicable SOCMI factor.
3. All relief valves are vented to the flare.
4. This speciation is an overall average distribution and may not represent all operations.

d = a*b*[1-(c/100)]

e = d*8760/2000

Speciation:

Pollutant	Wt %	Emission Rate	
		lb/hr	tpy
Ethylene	61.5%	0.58	2.53
Propane	31.1%	0.29	1.28
Propylene	1.5%	0.01	0.06
1,3-Butadiene	1.9%	0.02	0.08
Butenes	0.5%	0.00	0.02
Benzene	1.8%	0.02	0.07
C5+ (HAP)	0.5%	0.00	0.02
C5+ (non-HAP)	1.2%	0.01	0.05
Total VOC	100.0%	0.94	4.12
Total HAP		0.04	0.17

INEOS USA LLC
CHOCOLATE BAYOU PLANT
INITIAL PERMIT APPLICATION
FUGITIVE EMISSIONS (EPN: FUG-ADDF)

EQUIPMENT TYPE	SERVICE	VOC	COUNT	EMISSION FACTOR	REDUCTION CREDIT	VOC EMISSIONS	
				(lb/hr/source)[2]	(%)[1]	(lb/hr)	(tpy)
			a	b	c	d	e
Valves	Gas/Vapor	With Ethylene		0.0258			
		Average		0.0132			
		Without Ethylene	64	0.0089	97	0.02	0.07
	Light Liquid	With Ethylene		0.0459			
		Average		0.0089			
		Without Ethylene		0.0035			
	Heavy Liquid	With Ethylene		0.0005			
		Average		0.0005			
		Without Ethylene		0.0007			
Pump Seals	Light Liquid	With Ethylene		0.1440			
		Average		0.0439			
		Without Ethylene		0.0386			
	Heavy Liquid	With Ethylene		0.0046			
		Average		0.0190			
		Without Ethylene		0.0161			
Flanges/Connectors	Gas/Vapor	With Ethylene		0.0053			
		Average		0.0039			
		Without Ethylene	128	0.0029	30	0.26	1.14
	Light Liquid	With Ethylene		0.0052			
		Average		0.0005			
		Without Ethylene		0.0005			
	Heavy Liquid	All		0.00007			
Compressor Seals	All	All		0.5027			
Relief Valves	All	All		0.2293			
Open Ended Lines	All	With Ethylene		0.0075			
		Average		0.0038			
		Without Ethylene		0.004			
Sampling Connections	All	All		0.033			
Total			**192**		**Total**	**0.28**	**1.21**

Notes:

1. Reduction credit based on TCEQ - 28 VHP monitoring program.
2. Emissions were calculated using the applicable SOCMI factor.
3. All relief valves are vented to the flare.
4. This speciation is based on maximum content in natural gas.

Speciation:

Pollutant	Wt %	Emission Rate	
		lb/hr	tpy
Methane	98.0%	0.27	1.19
CO2e		5.70	24.96

d = a*b*[1-(c/100)]

e = d*8760/2000

INEOS USA LLC
CHOCOLATE BAYOU PLANT
INITIAL PERMIT APPLICATION
FUGITIVE EMISSIONS (EPN: FUG-SCR2)

EQUIPMENT TYPE	SERVICE	VOC	COUNT a	EMISSION FACTOR (lb/hr/source)[2] b	REDUCTION CREDIT (%)[1] c	VOC EMISSIONS (lb/hr) d	VOC EMISSIONS (tpy) e
Valves	Gas/Vapor	With Ethylene		0.0258			
		Average		0.0132			
		Without Ethylene	8	0.0089	97	<0.01	0.01
	Light Liquid	With Ethylene		0.0459			
		Average		0.0089			
		Without Ethylene	63	0.0035	97	0.01	0.03
	Heavy Liquid	With Ethylene		0.0005			
		Average		0.0005			
		Without Ethylene		0.0007			
Pump Seals	Light Liquid	With Ethylene		0.1440			
		Average		0.0439			
		Without Ethylene	4	0.0386	93	0.01	0.05
	Heavy Liquid	With Ethylene		0.0046			
		Average		0.0190			
		Without Ethylene		0.0161			
Flanges/Connectors	Gas/Vapor	With Ethylene		0.0053			
		Average		0.0039			
		Without Ethylene	19	0.0029	97	<0.01	0.01
	Light Liquid	With Ethylene		0.0052			
		Average		0.0005			
		Without Ethylene	135	0.0005	97	<0.01	0.01
	Heavy Liquid	All		0.00007			
Compressor Seals	All	All		0.5027			
Relief Valves	All	All	7.8	0.2293	97	0.05	0.24
Open Ended Lines	All	With Ethylene		0.0075			
		Average		0.0038			
		Without Ethylene		0.004			
Sampling Connections	All	All	4	0.033	97	<0.01	0.02
Total			**241**		**Total**	**0.08**	**0.35**

Notes:

1. Monitoring credits are for AVO inspections.
2. Emissions were calculated using the applicable SOCMI factor.
3. All relief valves are vented to the flare.
4. This speciation is an overall average distribution and may not representall operations.

d = a*b*[1-(c/100)]
e = d*8760/2000

Speciation:

Pollutant	Wt %	Emission Rate lb/hr	Emission Rate tpy
Ammonia	29.4%	0.02	0.10
Water	70.6%	0.06	0.25

INEOS USA LLC
CHOCOLATE BAYOU PLANT
INITIAL PERMIT APPLICATION
DECOKING DRUM EMISSIONS (EPN: DDF-106)

Emissions Basis

Coke is removed during the initial four hours of decoking. The estimated total hours of decoke operations is 420 hours/year, although the hourly maximum emissions are based on the coke being removed during a four hour period. Emission factors for CO and PM_{10} were provided by the coke drum manufacturer. VOC emissions from the decoke cyclone are due to leakage through block valves in the decoke header which are closed during normal operation. During decoking, CO_2 emissions are created from combusting the carbon build-up on the furnace tubes. Emission rates are based on the anticipated mass of coke and number of decokes per year. It is assumed that 46% of the coke combustion will be emitted in the form of particulates and 51% will be emitted as CO and CO_2. INEOS is still in the process of picking a vendor but will meet emission representations in this application. CO is more reactive and will tend to create CO_2 once exposed the cooler temperatures at the stack. Particulate emissions are based on the anticipated amount mass of coke in the drum and a control efficiency is applied.

Coke Formation on Furnace (lb):	8,114	
Coke Combusted:	51%	
Coke Combusted per Decoke (lb):	4,138	
Carry Over to Decoke Drum:	46%	
Carry Over to Decoke Drum per Decoke (lb):	3,733	
Decoke Frequency (decoke/yr):	12	
CO Emission Factor (lb/lb coke combusted):	0.10	
Molecular Weight of Coke (C):	12	
Molecular Weight of Carbon Monoxide (CO):	28	
Molecular Weight of Carbon Dioxide (CO_2):	44	
VOC Emission Factor (lb/hr-valve):	0.0038	*(Average SOCMI emission factor for open ended lines)*
Average Number of Valves:	24	

Emissions Summary

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
CO	103.46	2.48
VOC	0.09	0.01
CO_2	3,630.95	87.14
PM	2.29	0.05
PM_{10}	1.35	0.03
$PM_{2.5}$	0.84	0.02

Note: PM emissions include the total PM, PM_{10}, and $PM_{2.5}$ emissions. PM_{10} includes the total PM_{10} and $PM_{2.5}$ emissions.

CO Emissions

$$4{,}138\ \frac{\text{lb coke combusted}}{\text{decoke}} * 1\ \frac{\text{decoke}}{\text{cycle}} * 0.25\ \frac{\text{cycle}}{\text{hr}} * 0.10\ \frac{\text{lb CO}}{\text{lb coke combusted}} = \boxed{103.46\ \frac{\text{lb CO}}{\text{hr}}}$$

$$4{,}138\ \frac{\text{lb coke combusted}}{\text{decoke}} * 12\ \frac{\text{decoke}}{\text{yr}} * 0.10\ \frac{\text{lb CO}}{\text{lb coke combusted}} * \frac{1}{2{,}000}\ \frac{\text{ton}}{\text{lb}} = \boxed{2.48\ \frac{\text{ton CO}}{\text{yr}}}$$

CO_2 Emissions

$$4{,}138\ \frac{\text{lb coke formed}}{\text{decoke}} * 1\ \frac{\text{decoke}}{\text{cycle}} * 0.25\ \frac{\text{cycle}}{\text{hr}} * \frac{1}{12}\ \frac{\text{mol coke}}{\text{lb coke}} = 86\ \frac{\text{mol coke}}{\text{hr}}$$

$$103.46\ \frac{\text{lb CO}}{\text{hr}} * \frac{1}{28}\ \frac{\text{mol CO}}{\text{lb CO}} = 4\ \frac{\text{mol CO}}{\text{hr}}$$

$$4\ \frac{\text{mol CO}}{\text{hr}} * \frac{1}{1}\ \frac{\text{mol coke}}{\text{mol CO}} = 4\ \frac{\text{mol coke (converted to CO)}}{\text{hr}}$$

$$86\ \frac{\text{mol coke}}{\text{hr}} - 4\ \frac{\text{mol coke (converted to CO)}}{\text{hr}} = 83\ \frac{\text{mol coke (converted to CO}_2\text{)}}{\text{hr}}$$

$$83\ \frac{\text{mol coke (converted to CO}_2\text{)}}{\text{hr}} * \frac{1}{1}\ \frac{\text{mol CO}_2}{\text{mol coke}} * 44\ \frac{\text{lb CO}_2}{\text{mol CO}_2} = \boxed{3{,}630.95\ \frac{\text{lb CO}_2}{\text{hr}}}$$

$$4{,}138\ \frac{\text{lb coke formed}}{\text{decoke}} * 12\ \frac{\text{decoke}}{\text{yr}} * \frac{1}{12}\ \frac{\text{mol coke}}{\text{lb coke}} = 4{,}138\ \frac{\text{mol coke}}{\text{yr}}$$

$$2.48\ \frac{\text{ton CO}}{\text{yr}} * 2000\ \frac{\text{lb}}{\text{ton}} * \frac{1}{28}\ \frac{\text{mol CO}}{\text{lb CO}} = 177\ \frac{\text{mol CO}}{\text{yr}}$$

$$177\ \frac{\text{mol CO}}{\text{yr}} * \frac{1}{1}\ \frac{\text{mol coke}}{\text{mol CO}} = 177\ \frac{\text{mol coke (converted to CO)}}{\text{yr}}$$

$$4{,}138\ \frac{\text{mol coke}}{\text{yr}} - 177\ \frac{\text{mol coke (converted to CO)}}{\text{yr}} = 3{,}961\ \frac{\text{mol coke (converted to CO}_2\text{)}}{\text{yr}}$$

$$3{,}961\ \frac{\text{mol coke (converted to CO}_2\text{)}}{\text{yr}} * \frac{1}{1}\ \frac{\text{mol CO}_2}{\text{mol coke}} * 44\ \frac{\text{lb CO}_2}{\text{mol CO}_2} * \frac{1}{2000}\ \frac{\text{ton}}{\text{lb}} = \boxed{87.14\ \frac{\text{ton CO}_2}{\text{yr}}}$$

VOC Emissions

$$24\ \text{valves} * 0.0038\ \frac{\text{lb VOC}}{\text{hr-valve}} = \boxed{0.09\ \frac{\text{lb VOC}}{\text{hr}}}$$

$$0.09\ \frac{\text{lb VOC}}{\text{hr}} * 12\ \frac{\text{hr}}{\text{decoke}} * 12\ \frac{\text{decoke}}{\text{yr}} * \frac{1}{2000}\ \frac{\text{lb}}{\text{ton}} = \boxed{0.01\ \frac{\text{ton VOC}}{\text{yr}}}$$

Uncontrolled PM Emissions

$$3{,}733\ \frac{\text{lb coke carried over}}{\text{decoke}} * 1\ \frac{\text{decoke}}{\text{drum}} * 1\ \frac{\text{drums}}{\text{cycle}} * 0.25\ \frac{\text{cycle}}{\text{hr}} = \boxed{933.17\ \frac{\text{lb uncontrolled PM}}{\text{hr}}}$$

$$3{,}733\ \frac{\text{lb coke carried over}}{\text{decoke}} * 12\ \frac{\text{decoke}}{\text{yr}} * \frac{1}{2000}\ \frac{\text{ton}}{\text{lb}} = \boxed{22.40\ \frac{\text{ton uncontrolled PM}}{\text{yr}}}$$

Controlled Particulate Emissions

Particle Size	Control Efficiency	Distribution (wt%)	Maximum Hourly Emission (lb/hr)	Annual Emissions (ton/yr)
$PM_{2.5}$	50%	0.18%	0.84	0.02
PM_{10}	90%	0.55%	0.51	0.01

INEOS USA LLC
CHOCOLATE BAYOU PLANT
INITIAL PERMIT APPLICATION
SCR AMMONIA EMISSIONS (EPN: DDB-105)

Emissions Basis

Ammonia Molecular Weight:	17 lb / lbmol
Maximum NH_3 Exhaust Concentration:	20 ppm @ 10% xs O_2
Average NH_3 Exhaust Concentration:	10 ppm @ 10% xs O_2
Exhaust Flowrate:	14,034 lbmol/hr

Emissions Summary

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Ammonia	4.77	10.45

Ammonia Emissions

$$14{,}034\ \frac{\text{lbmol}}{\text{hr}} * \frac{20}{1{,}000{,}000}\ \frac{\text{lbmol NH}_3}{\text{lbmol}} * 17\ \frac{\text{lb NH}_3}{\text{lbmol NH}_3} = \boxed{4.77\ \frac{\text{lb NH}_3}{\text{hr}}}$$

$$14{,}034\ \frac{\text{lbmol}}{\text{hr}} * \frac{10}{1{,}000{,}000}\ \frac{\text{lbmol NH}_3}{\text{lbmol}} * 17\ \frac{\text{lb NH}_3}{\text{lbmol NH}_3} * 8{,}760\ \frac{\text{hr}}{\text{yr}} * \frac{1}{2{,}000}\ \frac{\text{ton}}{\text{lb}} = \boxed{10.45\ \frac{\text{ton NH}_3}{\text{yr}}}$$

Appendix C | Netting Tables

AGRIFOS FERTILIZER L.L.C.
PASADENA, TX
INEOS CHOCOLATE BAYOU NEW CRACKING FURNACE
PSD AND PN NOTICE APPLICABILITY TABLE

Proposed Emissions

Pollutant	Project Emission Increases (tpy)	PSD Threshold (tpy)	PSD Contemperaneous Netting Required?
NO_X	21.68	40	No
CO	97.88	100	No
VOC	16.29	NA	NA
SO_2	1.78	40	No
NH_3	10.55	NA	NA
PM	22.55	25	No
PM_{10}	17.80	15	Yes
$PM_{2.5}$	10.14	10	Yes

Proposed MAERT Increases

Pollutant	Proposed MAERT Increases (tpy)	PN Threshold (tpy)	PN Applicable?
NO_X	21.68	5	Yes
CO	97.88	50	Yes
VOC	16.29	5	Yes
SO_X	1.78	10	No
NH_3	10.55	5	Yes
PM	22.55	5	Yes
PM_{10}	17.80	5	Yes
$PM_{2.5}$	10.14	5	Yes

TABLE PSD-2

PROJECT CONTEMPORANEOUS CHANGES[1]

Company: INEOS USA LLC

Permit Application No. :

Criteria Pollutant: NO_X

	PROJECT DATE[2]	EMISSION UNIT AT WHICH REDUCTION OCCURED[3]		PERMIT No.	PROJECT NAME OR ACTIVITY	A	B	C		
		FIN	EPN			ALLOWABLE EMISSIONS AFTER THE ACTIVITY[4] (tons/year)	ACTUAL EMISSIONS PRIOR TO THE ACTIVITY[4] (tons/year)	(tons/year) DIFFERENCE (A-B)[6]	CREDITABLE DECREASE OR INCREASE[8]	REASON CODE[7]
	Nov 2008	N/A	N/A	95	Flexible Cap Insignificant Contribution 9%	105.31	0.00	105.31	105.31	
	Dec 2008	GT-1	A-100	95	Retrofit on Cogen	256.77	485.96	-229.19	-229.19	b
	May 2011	UTILCMP4	UTILCMP4	PBR	New Air Compressor at Utilities	2.57	0.00	2.57	2.57	
	May 2011	UTILCMP5	UTILCMP5	PBR	New Air Compressor at Utilities	2.57	0.00	2.57	2.57	
	May 2011	UTILCMP6	UTILCMP6	PBR	New Air Compressor at Utilities	2.57	0.00	2.57	2.57	
	Oct 2013	DDB-105	DDB-105		New Cracking Furnace at Olefins No. 2	21.68	0.00	21.68	21.68	
							TOTAL		-94.49	

NOTES:

1 Individual PSD-2 Tables should be used to summarize a combination of activities which may be considered a single project for each regulated pollutant.
2 Date activity occurred and is documented. Attach Table PSD-3 for each project reduction claimed which explains how the reduction is creditable.
3 Emission Point No. as designated in TNRCC Permit or Emissions Inventory.
4 All records and calculations for these values need to be available upon request. Actual emissions should be estimated as an average of the actual emissions over the two-year period prior to the Project's Activity Date.
5 Allowable (column A) - Actual (column B) for all emissions.
6 If portion of the decrease not creditable, enter creditable amount. If all of decrease is creditable or if this line is an increase, enter column C again. Sum all values in this column and place in box at bottom of column.
7 For emission decreases:
Enter one of the following reason codes:
e1a - 101.29(e)1(A) Shutdowns
e1b - 101.29(e)1(B) Continuous Emission Monitors
e1c - 101.29(e)1(C) Reduction by Review
e1d - 101.29(e)1(D) Reduction by Standardized Calculation
oth - oth Describe on Table PSD-3.
Also reference appropriate PSD-3 page of this submittal
8 Sum all values for this page.

TABLE PSD-2
PROJECT CONTEMPORANEOUS CHANGES[1]

Company: INEOS USA LLC

Permit Application No. :

Criteria Pollutant: VOC

						A	B	C		
	PROJECT DATE[2]	EMISSION UNIT AT WHICH REDUCTION OCCURED[3]		PERMIT No.	PROJECT NAME OR ACTIVITY	ALLOWABLE EMISSIONS AFTER THE ACTIVITY[4] (tons/year)	ACTUAL EMISSIONS PRIOR TO THE ACTIVITY[4] (tons/year)	(tons/year) DIFFERENCE (A-B)[6]	CREDITABLE DECREASE OR INCREASE[8]	REASON CODE[7]
		FIN	EPN							
1	Jan 2008	P2FLARE	GM-1401	5419	Polypropylene Flare	25.00	23.83	1.18	1.2	d
2	Jan 2008	FGE-801	FGE-801	5419	Polypropylene Cooling Tower (Process Area Shutdown)	0.00	0.21	-0.21	-0.2	
3	Jan 2008	P2VALVEFUG	FUG2VPP	5419	Process Fugitives (Process Area Shutdown)	0.00	38.25	-38.25	-38.2	
4	Jan 2008	P2CLASFIER	FGM-306A&B	5419	Pellet Classifier (Process Area Shutdown)	0.00	0.01	-0.01	0.0	
5	Jan 2008	P2FINBLDG	FINBLDG	5419	Polypropylene Finishing (Process Area Shutdown)	0.00	11.73	-11.73	-11.7	
6	Jan 2008	P2PELSEP	SEP	5419	PP2 Pellet Separator (Process Area Shutdown)	0.00	1.03	-1.03	-1.0	
7	Jan 2008	SHOPPER	SHOPPER	5419	PP2 Strings Hopper (Process Area Shutdown)	0.00	2.94	-2.94	-2.9	
8	Jan 2008	P2FUGWC	FUGWCPP2	5419	PP2 wastewater collection (Process Area Shutdown)	0.00	8.90	-8.90	-8.90	
9	Nov 2008	N/A	N/A	95	Flexible Cap Insignificant factor contribution	58.30	0.00	58.30	58.30	
10	May 2011	UTILCMP4	UTILCMP4	PBR	New Air Compressor at Utilities	0.98	0.00	0.98	0.98	
11	May 2011	UTILCMP5	UTILCMP5	PBR	New Air Compressor at Utilities	0.98	0.00	0.98	0.98	
12	May 2011	UTILCMP6	UTILCMP6	PBR	New Air Compressor at Utilities	0.98	0.00	0.98	0.98	
13	Oct 2013	DDB-105	DDB-105		New Cracking Furnace at Olefins No. 2	16.28	0.00	16.28	16.28	
14	Oct 2013	FUG-ADDF	FUG-ADDF		New Cracking Furnace at Olefins No. 2	4.12	0.00	4.12	4.12	
15	Oct 2013	DDF-106	DDF-106		New Cracking Furnace at Olefins No. 2	0.01	0.00	0.01	0.01	
							Total		19.78	

NOTES:

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2 Date activity occurred and is documented. Attach Table PSD-3 for each project reduction claimed which explains how the reduction is creditable.
3 Emission Point No. as designated in TNRCC Permit or Emissions Inventory.
4 All records and calculations for these values need to be available upon request. Actual emissions should be estimated as an average of the actual emissions over the two-year period prior to the Project's Activity Date.
5 Allowable (column A) - Actual (column B) for all emissions.
6 If portion of the decrease not creditable, enter creditable amount. If all of decrease is creditable or if this line is an increase, enter column C again. Sum all values in this column and place in box at bottom of column.
7 For emission decreases:
Enter one of the following reason codes:
e1a - 101.29(e)1(A) Shutdowns
e1b - 101.29(e)1(B) Continuous Emission Monitors
e1c - 101.29(e)1(C) Reduction by Review
e1d - 101.29(e)1(D) Reduction by Standardized Calculation
oth - oth Describe on Table PSD-3.
Also reference appropriate PSD-3 page of this submittal
8 Sum all values for this page.

TABLE PSD-2

PROJECT CONTEMPORANEOUS CHANGES[1]

Company: INEOS USA LLC

Permit Application No. :

Criteria Pollutant: CO2e

	PROJECT DATE[2]	EMISSION UNIT AT WHICH REDUCTION OCCURED[3]		PERMIT No.	PROJECT NAME OR ACTIVITY	A	B	C	CREDITABLE DECREASE OR INCREASE[8]	REASON CODE[7]
		FIN	EPN			ALLOWABLE EMISSIONS AFTER THE ACTIVITY[4] (tons/year)	ACTUAL EMISSIONS PRIOR TO THE ACTIVITY[4] (tons/year)	(tons/year) DIFFERENCE (A-B)[6]		
	May 2011	UTILCMP4	UTILCMP4	PBR	New Air Compressor at Utilities	745	0	745	745	
	May 2011	UTILCMP5	UTILCMP5	PBR	New Air Compressor at Utilities	745	0	745	745	
	May 2011	UTILCMP6	UTILCMP6	PBR	New Air Compressor at Utilities	745	0	745	745	
	Oct 2011	OL2COMP2	OL2COMP2	PBR	New Air Compressor at Olefins No. 2	590	0	590	590	
	Oct 2013	DDF-106	DDF-106		New Decoke Stack at Olefins No. 2	87	0	87	87	
	Oct 2013	FUG-ADDF	FUG-ADDF		New Process Fugitives	25	1	24	24	
	Oct 2013	DDB-105	DDB-105		New Cracking Furnace at Olefins No. 2	216667	0	216667	216667	
							TOTAL		219604	

NOTES:

1 Individual PSD-2 Tables should be used to summarize a combination of activities which may be considered a single project for each regulated pollutant

2 Date activity occurred and is documented. Attach Table PSD-3 for each project reduction claimed which explains how the reduction is creditable

3 Emission Point No. as designated in TNRCC Permit or Emissions Inventory.

4 All records and calculations for these values need to be available upon request. Actual emissions should be estimated as an average of the actual emissions over the two-year period prior tc the Project's Activity Date.

5 Allowable (column A) - Actual (column B) for all emissions

6 If portion of the decrease not creditable, enter creditable amount. If all of decrease is creditable or if this line is an increase, enter column C again. Sum all values in this column and place ir box at bottom of column.

7 For emission decreases:
Enter one of the following reason codes:
e1a - 101.29(e)1(A) Shutdowns
e1b - 101.29(e)1(B) Continuous Emission Monitors
e1c - 101.29(e)1(C) Reduction by Review
e1d - 101.29(e)1(D) Reduction by Standardized Calculation
oth - oth Describe on Table PSD-3.
Also reference appropriate PSD-3 page of this submittal

8 Sum all values for this page.

Appendix D | RBLC/BACT Tables

RACT/BACT/LAER Clearinghouse
Results for Furnaces (PM_{10}, $PM_{2.5}$)

RBCL ID	Facility	Facility Description	SIC Code	County/ Parish	State	Permit Number	Permit Date	Process	Primary Fuel	Throughput	Throughput Unit	Pollutant	Emission Limit 1	Emission Limit 2	Standard Emission Limit	Control Description	Basis	Comments
LA-0213	VALERO REFINING NEW ORLEANS, LLC ST. CHARLES REFINERY	PETROLEUM REFINERY. PROJECT INVOLVES INCREASE IN CAPACITY FROM 220,000 TO 380,000 BARRELS PER DAY (REFINERY EXPANSION).	2911	ST. CHARLES	LA	PSD-LA-619(M5)	11/17/2009	HEATERS/REBOILERS (2004-1 - 8 AND 2005-1 ,2,5,8,9,10,25) (F-72-703)	REFINERY GAS AND NATURAL GAS	24-1274	MMBTU/H	PM10	NONE INCLUDED	NONE INCLUDED	NOT AVAILABLE	PROPER EQUIPMENT DESIGN AND OPERATION, GOOD COMBUSTION PRACTCES AND USE OF GASEOUS FUELS		
								HEATERS/REBOILERS (20018-1 -9) (2008-10,11, AND 40)	PROCESS GAS AND NATURAL GAS	36-880	MMBTU/H	PM10	NONE INCLUDED	NONE INCLUDED	NOT AVAILABLE	COMPLY WITH 40 CFR NNN AND RRR		
								HEATERS (H-39,02 AND -03)(4-81, 5-81)	REFINERY FUEL GAS	68-90	MMBTU/H	PM10	NONE INCLUDED	NONE INCLUDED	0.0074 LB/MMBTU	PROPER EQUIPMENT DESIGN AND OPERATION, GOOD COMBUSTION PRACTCES AND USE OF GASEOUS FUELS		
								BOILERS (94-43 AND 94-45)	REFINERY FUEL GAS AND NATURAL GAS	354	MMBTU/H	PM10	2.6 LB/H			CLEAN FUELS		
								BOILERS (2)	REFINERY FUEL GAS AND NATURAL GAS	374	MMBTU/H	PM10	2.53 LB/H	11.1 T/YR		CLEAN FUELS AND VISIBLE EMISSIONS 20% OPACITY OVER 6 MIN AVG		
								BOILERS	NATURAL GAS AND TAIL GAS	1200	MMBTU/H	PM10	18.7 LB/H (3 HR AVG)	81.9 TPY	0.0156 LB/MMBTU	GOOD COMBUSTION PRACTICES AND VISIBLE EMISSIONS LIMITED 10% OPACITY OVER 6 MINUTE AVERAGE		
								UTILITY AND LARGE INDUSTRIAL SIZE BOILERS/FURNACES	REFINERY GAS	363	MMBTU/H	PM10	3.4000 LB/H (calendar day)			(N) BURN ONLY REFINERY FUEL GAS/NATURAL GAS	BACT-PSD	PM10 EMISSIONS ESTIMATED USING EMISSION FACTOR BASED ON BP STACK TESTING ON SIMILAR BOILERS BURNING RFG. EMISSSION FACTOR IS 12.74 LB OF TOTAL PARTICULATE (FILTERABLE PLUS CONDENSABLE) PER MILLION STANDARD CUBIC FEET OF RFG COMBUSTED.
TX-0526	AIR PRODUCTS	AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	4931	JEFFERSON	TX	NA 63 AND 39693	8/18/2006	REFORMER FURNACE STACK	STEAM	1373	MMBTU/H	PM/PM10	16.7000 LB/H	63.0000 T/YR	0.0075 LB/MMBTU	None	None	EQUIPPED WITH AN AMMONIA SLIP SCR.
LA-0206	EXXONMOBIL REFINING AND SUPPLY COMPANY (INCREASE IN CAPACITY)	PETROLEUM REFINERY	2911	EAST BATON ROUGE	LA	PSD-LA-667(M-1)	02/18/2004 (actual)	PIPESTILL, COKER, CAT COMPLEX, & LIGHT ENDS FURNACES		283-555	MMBTU/H	PM10	0.0080 LB/MMBTU		0.0080 LB/MMBTU	(P) GOOD ENGINEERING DESIGN AND PROPER COMBUSTION PRACTICES	BACT-PSD	
								PIPESTILL, COKER, HYDROCRACKING, & LIGHT ENDS FURNACES		116-239	MMBTU/H	PM10	0.0080 LB/MMBTU		0.0080 LB/MMBTU	(P) GOOD ENGINEERING DESIGN AND PROPER COMBUSTION PRACTICES	BACT-PSD	
								POWERFORMING & LIGHT ENDS FURNACES		120-222	MMBTU/H	PM10	0.0080 LB/MMBTU		0.0080 LB/MMBTU	(P) GOOD ENGINEERING DESIGN AND PROPER COMBUSTION PRACTICES	BACT-PSD	
								POWERFORMING 2 & EAST LIGHT ENDS FURNACES		22-82	MMBTU/H	PM/PM10	0.0080 LB/MMBTU		0.0080 LB/MMBTU	(P) GOOD ENGINEERING DESIGN AND PROPER COMBUSTION PRACTICES	BACT-PSD	
								REFORMING, HYDROFINING, & HEAVY CAT FURNACES		46-80	MMBTU/H	PM10	0.0080 LB/MMBTU		0.0080 LB/MMBTU	(P) GOOD ENGINEERING DESIGN AND PROPER COMBUSTION PRACTICES	BACT-PSD	
								FEED PREPARATION FURNACES F-30 & F-31		352.00	MMBTU/H	PM10	0.0080 LB/MMBTU		0.0080 LB/MMBTU	(P) GOOD ENGINEERING DESIGN AND PROPER COMBUSTION PRACTICES	BACT-PSD	
LA-0123	EXXONMOBIL REFINING AND SUPPLY COMPANY	REFINING CLEAN GASOLINE PROJECT	2911	EAST BATON ROUGE PARISH	LA	PSD-LA-667, INTEREST #2638	04/26/2002 (actual)	HYDROFINER FURNACE		150	MMBTU/H	PM10	1.2000 LB/H	4.4900 T/YR	0.0080 LB/MMBTU CALCULATED USING THROUGHPUT	(P) GOOD COMBUSTION PRACTICES, GOOD ENGINEERING DESIGN, AND CLEAN BURNING FUEL		
								HYDROFINER FURNACE		197	MMBTU/H	PM10	1.5800 LB/H	6.1300 T/YR	0.0080 LB/MMBTU CALCULATED USING THROUGHPUT	(P) GOOD COMBUSTION PRACTICES, GOOD ENGINEERING DESIGN, AND CLEAN BURNING FUEL		
								FRACTIONATOR FURNACE		360.00	MMBTU/H	PM10	2.8800 LB/H	10.7600 T/YR	0.0080 LB/MMBTU CALCULATED USING THROUGHPUT	(P) GOOD COMBUSTION PRACTICES, GOOD ENGINEERING DESIGN, AND CLEAN BURNING FUEL	BACT-PSD	
TX-0339	EXXON MOBIL CHEMICAL COMPANY	OLEFINS PLANT (ADD A NEW CRACKING FURNACE)	2869	HARRIS	TX	PSD-TX-302 (M2)	04/05/2001 (actual)	FURNACE AF-01	ETHANE	350	MMBTU/H	PM	1.1000 LB/H	3.2000 T/YR	0.0030 LB/MMBTU CALCULATED USING THROUGHPUT	None	Other Case-by-Case	
								FURNACE BF-01	ETHANE	339	MMBTU/H	PM	1.0500 LB/H	3.8000 T/YR	0.0030 LB/MMBTU CALCULATED USING THROUGHPUT	None	Other Case-by-Case	
								FURNACE CF-01	ETHANE	350	MMBTU/H	PM	1.1000 LB/H	3.4000 T/YR	0.0030 LB/MMBTU CALCULATED USING THROUGHPUT	None	Other Case-by-Case	
								FURNACE DF-01	ETHANE	350	MMBTU/H	PM	1.1000 LB/H	3.0000 T/YR	0.0030 LB/MMBTU CALCULATED USING THROUGHPUT	None	Other Case-by-Case	
								FURNACE EF-01	ETHANE	350	MMBTU/H	PM	1.1000 LB/H	2.9000 T/YR	0.0030 LB/MMBTU	None	Other Case-by-Case	
								FURNACE FF-01	ETHANE	350	MMBTU/H	PM	1.1000 LB/H	3.5000 T/YR	0.0030 LB/MMBTU CALCULATED USING THROUGHPUT	None	Other Case-by-Case	
								FURNACE GF-01	ETHANE	350	MMBTU/H	PM	1.1000 LB/H	3.8000 T/YR	0.0030 LB/MMBTU CALCULATED USING THROUGHPUT	None	Other Case-by-Case	
								(2) FURNACES, IF-01 & JF-01	ETHANE	341.00	MMBTU/H	PM	1.0500 LB/H EACH	4.0400 T/YR EACH	0.0030 LB/MMBTU EACH, CALCULATED USING MAX THROUGPUT	None	Other Case-by-Case	
								FURNACE OF-01	ETHANE	300.00	MMBTU/H	PM	1.0000 LB/H	4.0000 T/YR	0.0030 LB/MMBTU EACH, CALCULATED USING MAX THROUGPUT	None	Other Case-by-Case	
								FURNACE QF-01	ETHANE	300.00	MMBTU/H	PM	1.0000 LB/H	3.8000 T/YR	0.0030 LB/MMBTU CALCULATED USING MAX THROUGHPUT	None	Other Case-by-Case	
								(6) FURNACES, XAF-01 THRU XFF-01	ETHANE	333.00	MMBTU/H	PM	1.3300 LB/H EACH	31.9000 T/YR COMBINED	0.0040 LB/MMBTU EACH, CALCULATED USING MAX THROUGHPUT	None	Other Case-by-Case	SUBJECT TO PSD REVIEW UNDER PSD-TX-302M1
								FURNACE HF-01	ETHANE	238	MMBTU/H	PM/PM10	0.73 LB/H	3.8000 T/YR	0.0030 LB/MMBTU CALCULATED USING THROUGHPUT	None		
								FURNACE XGF-01	ETHANE	502.00	MMBTU/H	PM/PM10	2.0000 LB/H	8.4000 T/YR	0.0040 LB/MMBTU CALCULATED USING MAX THROUGHPUT	None	Other Case-by-Case	
TX-0379	EXXONMOBIL OIL CORPORATION	PETROELUM REFINERY	2911	JEFFERSON	TX	PSD-TX-992	06/10/2002 (actual)	FCCU CO BOILER STACK (PRESCRUBBER), 06STK-001				PM	155.0000 LB/H	675.0000 T/YR	1.0000 LB/ 1000 LB COKE	None	BACT-PSD	
TX-0475	FORMOSA PLASTICS CORPORATION TEXAS	COMFORT PLANT	2821	CALHOUN	TX	19168 / PSD-TX-760M6	05/09/2005 (actual)	PYROLYSIS FURNACES (1001-1008, 1009 B)	FUEL GAS	250	MMBTU/H	PM10	0.5000 LB/H	2.2000 T/YR	0.002 LB/MMBTU CALCULATED	None	NA	
								PYROLYSIS FURNACE (1010B)	FUEL GAS	250	MMBTU/H	PM10	0.5000 LB/H	2.2000 T/YR	0.002 LB/MMBTU CALCULATED	None	NA	
								PYROLYSIS FURNACE (1054-1056)	FUEL GAS	250	MMBTU/H	PM	0.5100 LB/H	18.9900 T/YR	0.00204 LB/MMBTU CALCULATED	None	NA	
								PYROLYSIS FURNACE (1057-1062, 1091)	FUEL GAS	250	MMBTU/H	PM	0.5100 LB/H	18.9900 T/YR	0.00204 LB/MMBTU CALCULATED	None	NA	
								REBOILER	FUEL GAS	250	MMBTU/H	PM10	0.03 LB/H	0.13 T/YR				
								REGENERATION HEATER (Misc. Boilers, Furnaces, Heaters)				PM	0.1500 LB/H	0.0300 T/YR				
								PYROLYSIS FURNACE (N1011-1012)	FUEL GAS	250	MMBTU/H	PM	0.9900 LB/H	4.3300 T/YR	0.004 LB/MMBTU CALCULATED	None	NA	

RACT/BACT/LAER Clearinghouse
Results for Furnaces (PM_{10}, $PM_{2.5}$)

RBCL ID	Facility	Facility Description	SIC Code	County/ Parish	State	Permit Number	Permit Date	Process	Primary Fuel	Throughput	Throughput Unit	Pollutant	Emission Limit 1	Emission Limit 2	Standard Emission Limit	Control Description	Basis	Comments
TX-0511	BASF FINA PETROCHEMICALS	ETHYLENE/PROPYLENE CRACKER (MODIFY EXISTING FACILITY)	4932	JEFFERSON	TX	PSD-TX 903M1, N-007M1 AND 36644	02/03/2006 (actual)	RECYCLE ETHANE CRACKING FURNACE				PM10	1.5100 LB/H	6.6100 T/YR		None	BACT-PSD	
TX-0347	BP AMOCO CHOCOLATE BAYOU	INCREASE ETHYLENE CAPACITY	2869	BRAZORIA	TX	PSD-TX-754	10/16/2001	CRACKING FURNACE 1-D	NATURAL GAS (INCLUDES PROPANE AND LPG)	90		PM10			0.007 LB/MMBTU	GOOD COMBUSTION PRACTICES AND NATURAL GAS AS FUEL		
								MULTIPLE HEATERS	REFINERY FUEL GAS	75-138								
								BOILERS	REFINERY FUEL GAS	525.7								
								HEATER	NATURAL GAS	155.2								
LA-0211	MARATHON PETROLEUM CO LLC GARYVILLE REFINERY	INCREASE CAPACITY FROM 180,000 BBL/DAY TO 545,OOO BBL/DAY	2911	ST JOHN THE BAPTIST	LA	PSD-LA-719	12/27/2006	MULTIPLE CRUDE HEATERS	REFINERY FUEL GAS	386-480	MMBTU/H	PM10			0.0075 LB/MMBTU (3 HR AVG)	PROPER DESIGN OPERATION AND GOOD ENGINEERING PRACTICE		
								MULTIPLE HEATERS	REFINERY FUEL GAS	75-138	MMBTU/H	PM10			0.0075 LB/MMBTU (3 HR AVG)	PROPER DESIGN OPERATION AND GOOD ENGINEERING PRACTICE		
								BOILERS	REFINERY FUEL GAS	525.7	MMBTU/H	PM10			0.0075 LB/MMBTU (3 HR AVG)	PROPER DESIGN OPERATION AND GOOD ENGINEERING PRACTICE		
								HEATER	NATURAL GAS	155.2	MMBTU/H	PM10			0.0075 LB/MMBTU (3 HR AVG)	PROPER DESIGN OPERATION AND GOOD ENGINEERING PRACTICE		
LA-0376	DOW CHEMICAL COMPANY	FREEPORT CONGEN FACILITIES (6 BOILERS)	2911	BRAZORIA	TX	PSD-TX-9867	11/26/2002	STEAM BOILERS	NATURAL GAS	457.5	MMBTU/H	PM10	7.85 LB/H	60.50 T/YR	0.017 LB/MMBTU CALCULATED	FIRE NATURAL GAS, GOOD COMBUSTION PRACTICES VISIBLE EMISSIONS LIMITED TO 5% OPACITY OVER 6 MIN AVG		
								STEAM BOILERS (EQUIPPED WITH AMMONIA SCR)	NATURAL GAS	382	MMBTU/H	PM10	6.5 LB/H	101.1 T/YR	0.017 LB/MMBTU CALCULATED	FIRE NATURAL GAS, GOOD COMBUSTION PRACTICES VISIBLE EMISSIONS LIMITED TO 5% OPACITY OVER 6 MIN AVG	BACT-PSD	
TX-0375	LYONDELL - CITGO REFINING, LP	LYONDELL - CITGO REFINING, LP	2911	HARRIS	TX	PSD-TX-985	03/14/2002	BTU- NO.3 REACTOR FEED HEATER		58.95	MMBTU/H	PM	0.7500 LB/H	3.2900 T/YR	0.0130 LB/MMBTU CALCULATED		BACT-PSD	
								BTU-NO.4 REACTOR FEED HEATER		49	MMBTU/H	PM	0.6300 LB/H	2.7400 T/YR	0.0130 LB/MMBTU		BACT-PSD	
								BTU-REFORMATE STABILIZER REBOILER		54.77	MMBTU/H	PM	0.7000 LB/H	3.0600 T/YR	0.0130 LB/MMBTU CALCULATED		BACT-PSD	
								ISOM II WEST REACTOR FEED HEATER		104.25	MMBTU/H	PM	1.3300 LB/H	5.8200 T/YR	0.0130 LB/MMBTU CALCULATED		BACT-PSD	
								ISOM II COMBINATION SPLITTER HEATER		77.62	MMBTU/H	PM	0.9900 LB/H	4.3300 T/YR	0.0130 LB/MMBTU CALCULATED		BACT-PSD	
								ISOM II XYLENE RERUN TOWER HEATER		83.7	MMBTU/H	PM	1.0600 LB/H	4.6700 T/YR	0.0130 LB/MMBTU CALCULATED		BACT-PSD	
								ISOM II EAST REACTOR FEED HEATER		75	MMBTU/H	PM	0.9600 LB/H	3.3200 T/YR	0.0130 LB/MMBTU CALCULATED		BACT-PSD	
								ORTHOXYLENE I HEATER		96.23	MMBTU/H	PM	1.2300 LB/H	5.3700 T/YR	0.0130 LB/MMBTU CALCULATED		BACT-PSD	
								ORTHOXYLENE II HEATER		226.42	MMBTU/H	PM	2.8900 LB/H	12.6500 T/YR	0.0130 LB/MMBTU CALCULATED		BACT-PSD	
								BTU-NO. 1 REACTOR FEED HEATER		121.74	MMBTU/H	PM	1.5600 LB/H	6.8000 T/YR	0.0130 LB/MMBTU CALCULATED FROM FINAL HOURLY EMISSION LIMIT		BACT-PSD	
								BTU-NO.2 REACTOR FEED HEATER		69.68	MMBTU/H	PM	0.8900 LB/H	3.8900 T/YR	0.0130 LB/MMBTU CALCULATED		BACT-PSD	
								BENZENE STABILIZER HEATER	PETRO REFIN GAS	38.34	MMBTU/H	PM	0.2900 LB/H	1.2500 T/YR	0.0070 LB/MMBTU CALCULATED		BACT-PSD	
								BOILER NO. 12		245	MMBTU/H	PM	1.8300 LB/H	8.0000 T/YR	0.0070 LB/MMBTU CALCULATED		BACT-PSD	
TX-0478	CITGO REFINING AND CHEMICALS COMAPNY LP	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	2869	NUECES	TX	PSD-TX-408M3	4/20/2005	MIXED DISTILLATE HYDROHEATER		62	MMBTU/H	PM10	0.4600 LB/H	2.0000 T/YR		None	BACT-PSD	
								DHT CHARGER HEATER				PM10	0.7100 LB/H	2.9000 T/YR		None	BACT-PSD	THE MDH UNIT REMOVES ORGANIC NITROGEN AND SULFUR FROM THE FEED STREAMS. FEEDSTOCK IS MIXED WITH HYDROGEN , HEATED, AND FED TO A REACTOR. A CATALYTIC REACTION CONVERTS THE ORGANIC SULFUR TO HYDROGEN SULFIDE AND THE NITROGEN COMPOUNDS TO AMMONIA. THE EFFLUENT STREAM IS COOLED AND EXCESS HYDROGEN REMOVED FOR RECYCLE. HYDROGEN SULFIDE IS REMOVED FROM THE HYDROGEN STREAM BY AN AMINE ABSORBER AND ROUTED TO THE SRU. NEW EQUIPMENT UNDER THE AMENDMENT INCLUDES A SECOND REACTOR, ADDITIONAL PREHEAT TRAIN, AN ADDITIONAL REACTOR PRODUCT FLASH DRUM, A HYDROGEN PURIFICATION MEMBRANE AND AN ADDITIONAL HYDROGEN MAKEUP COMPRESSOR. AS PART OF THE AMENDMENT, THE FRACTIONATOR REBOILER WILL BE RETROFIT WITH LOW NOX BURNERS.
								DHT STRIPPER REBOILER	REFINERY FUEL GAS			PM10	0.6400 LB/H	2.6000 T/YR		None	BACT-PSD	
								NO.3 BOILER	REFINERY FUEL GAS	99	MMBTU/H	PM10	0.7400 LB/H	3.2000 T/YR		None	BACT-PSD	
								COKE STORAGE AND HANDLING FACILITIES				PM10	3.3000 LB/H	14.4000 T/YR		None	BACT-PSD	
								COKER HEATER		291	MMBTU/H	PM10	2.2000 LB/H	9.5000 T/YR		None	BACT-PSD	THE COKER UNIT USES THERMAL CRACKING TO UPGRADE HEAVY BOTTOM STREAMS TO DISTILLATES. THE OVERHEAD PRODUCTS ARE SENT TO A FRACTIONATOR FOR ADDITIONAL SEPARATION. A COMBINATION OF COMPRESSION, ADSORPTION, STRIPPING AND DISTILLATION PRODUCES THE FOLLOWING PRODUCT STREAMS: LPG/ALKY FEED, GASOLINE, NAPHATHA, KEROSENE, LIGHT COKER GAS OIL, HEAVY COKER GAS OIL AND FUEL GAS. THE COKER UNIT ALSO PRODUCES A SOLID PETROLEUM COKE PRODUCT WHICH IS STEAM CUT FROM THE COKE DRUMS ONTO A COKE PAD. THIS UNIT IS UNAFFECTED BY THE AMENDMENT.
								MIXED DISTILLATE HYDROHEATER REBOILER HEATER	REFINERY FUEL GAS	82	MMBTU/H	PM10	0.6100 LB/H	2.7000 T/YR		None	BACT-PSD	THE MDH UNIT REMOVES ORGANIC NITROGEN AND SULFUR FROM THE FEED STREAMS. FEEDSTOCK IS MIXED WITH HYDROGEN , HEATED, AND FED TO A REACTOR. A CATALYTIC REACTION CONVERTS THE ORGANIC SULFUR TO HYDROGEN SULFIDE AND THE NITROGEN COMPOUNDS TO AMMONIA. THE EFFLUENT STREAM IS COOLED AND EXCESS HYDROGEN REMOVED FOR RECYCLE. HYDROGEN SULFIDE IS REMOVED FROM THE HYDROGEN STREAM BY AN AMINE ABSORBER AND ROUTED TO THE SRU. NEW EQUIPMENT UNDER THE AMENDMENT INCLUDES A SECOND REACTOR, ADDITIONAL PREHEAT TRAIN, AN ADDITIONAL REACTOR PRODUCT FLASH DRUM, A HYDROGEN PURIFICATION MEMBRANE AND AN ADDITIONAL HYDROGEN MAKEUP COMPRESSOR. AS PART OF THE AMENDMENT, THE FRACTIONATOR REBOILER WILL BE RETROFIT WITH LOW NOX BURNERS.

RACT/BACT/LAER Clearinghouse
Results for Furnaces (PM_{10}, $PM_{2.5}$)

RBCL ID	Facility	Facility Description	SIC Code	County/ Parish	State	Permit Number	Permit Date	Process	Primary Fuel	Throughput	Throughput Unit	Pollutant	Emission Limit 1	Emission Limit 2	Standard Emission Limit	Control Description	Basis	Comments
LA-0166	ORION REFINING CORP (NOW VALERO)	ORION REFINING CORP (NOW VALERO)	2911	ST. CHARLES PARISH	LA	PSD-LA-619	1/10/2002	HEATER H-15-01B		46	MMBTU/H	PM10	0.6400 LB/H	2.8000 T/YR	0.0139 LB/MMBTU	GASEOUS FUEL/ GOOD COMBUSTION PRACTICES	BACT-PSD	
								FCC REGENERATOR		110.00 TO 130	MMBTU/H	PM10	86.1000 LB/H	327.0000 T/YR		BELCO WET GAS SCRUBBER	BACT-PSD	
								HEATER H-15-01A		46	MMBTU/H	PM10	0.6400 LB/H	2.8000 T/YR	0.0139 LB/MMBTU	GASEOUS FUEL, GOOD COMBUSTION PROCESSES	BACT-PSD	
								HEATER F-72-703	REFINERY FUEL GAS	528	MMBTU/H	PM10	2.6000 LB/H	11.6000 T/YR	0.0050 LB/MMBTU	BURNING CLEAN FUEL (NATURAL GAS AND FUEL GAS), AND UTILIZING GOOD COMBUSTION PRACTICES.	BACT-PSD	
LA-0193	COS-MAR COMPANY	STYRENE MONOMER PLANT	2865	IBERVILLE	LA	PSD-LA-690	2/11/2003	REGENERATION GAS HEATER HS-2102		14.4	MMBTU/H	PM10	0.1100 LB/H HOURLY MAXIMUM		0.0100 LB/MMBTU ANNUAL AVERAGE	USE OF CLEAN BURNING FUELS (NATURAL GAS)	BACT-PSD, OPERATING PERMIT	ANNUAL PM10 EMISSIONS FROM THE FOLLOWING SOURCES ARE CAPPED AT 108.3 TPY: 145-02-A, 145-02-B, 145-02-C, 145-02-D, 145-02-E, 145-02-F, 145-02-G, 145-02-H, 145-02-I, 145-02-J, 145-02-K, 145-02-L, 145-02-M, 145-02-N, 145-02-O, & 145-02-P.
								REHEATER HS-8220	NATURAL GAS	195.00	MMBTU/H	PM10	1.5000 LB/H HOURLY MAXIMUM		0.0100 LB/MMBTU ANNUAL AVERAGE	USE OF CLEAN BURNING FUELS (NATURAL GAS AND PROCESS GAS)	BACT-PSD, OPERATING PERMIT	ANNUAL PM10 EMISSIONS FROM THE FOLLOWING SOURCES ARE CAPPED AT 108.3 TPY: 145-02-A, 145-02-B, 145-02-C, 145-02-D, 145-02-E, 145-02-F, 145-02-G, 145-02-H, 145-02-I, 145-02-J, 145-02-K, 145-02-L, 145-02-M, 145-02-N, 145-02-O, & 145-02-P.
								BZ RECOVERY COLUMN HEATER HS-2103		182.1	MMBTU/H	PM10	1.4000 LB/H HOURLY MAXIMUM		0.0100 LB/MMBTU ANNUAL AVERAGE	USE OF CLEAN BURNING FUELS (NATURAL GAS)	BACT-PSD, OPERATING PERMIT	ANNUAL PM10 EMISSIONS FROM THE FOLLOWING SOURCES ARE CAPPED AT 108.3 TPY: 145-02-A, 145-02-B, 145-02-C, 145-02-D, 145-02-E, 145-02-F, 145-02-G, 145-02-H, 145-02-I, 145-02-J, 145-02-K, 145-02-L, 145-02-M, 145-02-N, 145-02-O, & 145-02-P.
								EB RECOVERY COLUMN HEATER HS-2104		269.3	MMBTU/H	PM10	2.0000 LB/H HOURLY MAXIMUM		0.0100 LB/MMBTU ANNUAL AVERAGE	USE OF CLEAN BURNING FUELS (NATURAL GAS)	BACT-PSD, OPERATING PERMIT	ANNUAL PM10 EMISSIONS FROM THE FOLLOWING SOURCES ARE CAPPED AT 108.3 TPY: 145-02-A, 145-02-B, 145-02-C, 145-02-D, 145-02-E, 145-02-F, 145-02-G, 145-02-H, 145-02-I, 145-02-J, 145-02-K, 145-02-L, 145-02-M, 145-02-N, 145-02-O, & 145-02-P.
								PROCESS SUPERHEATER HS-8201/8219	PROCESS GAS	280	MMBTU/H	PM10	2.1000 LB/H HOURLY MAXIMUM		0.0100 LB/MMBTU ANNUAL AVERAGE	USE OF CLEAN BURNING FUELS (NATURAL GAS AND PROCESS GAS)	BACT-PSD, OPERATING PERMIT	ANNUAL PM10 EMISSIONS FROM THE FOLLOWING SOURCES ARE CAPPED AT 108.3 TPY: 145-02-A, 145-02-B, 145-02-C, 145-02-D, 145-02-E, 145-02-F, 145-02-G, 145-02-H, 145-02-I, 145-02-J, 145-02-K, 145-02-L, 145-02-M, 145-02-N, 145-02-O, & 145-02-P.
								PROCESS SUPERHEATER HF-1201/1219	PROCESS GAS	298.9	MMBTU/H	PM10	2.2000 LB/H HOURLY MAXIMUM		0.0100 LB/MMBTU ANNUAL AVERAGE	USE OF CLEAN BURNING FUELS (NATURAL GAS AND PROCESS GAS)	BACT-PSD, OPERATING PERMIT	ANNUAL PM10 EMISSIONS FROM THE FOLLOWING SOURCES ARE CAPPED AT 108.3 TPY: 145-02-A, 145-02-B, 145-02-C, 145-02-D, 145-02-E, 145-02-F, 145-02-G, 145-02-H, 145-02-I, 145-02-J, 145-02-K, 145-02-L, 145-02-M, 145-02-N, 145-02-O, & 145-02-P.
								PEB RECOVERY COLUMN HEATER HS-2105		25.2	MMBTU/H	PM10	0.1900 LB/H HOURLY MAXIMUM		0.0100 LB/MMBTU ANNUAL AVERAGE	USE OF CLEAN BURNING FUELS (NATURAL GAS)	BACT-PSD, OPERATING PERMIT	ANNUAL PM10 EMISSIONS FROM THE FOLLOWING SOURCES ARE CAPPED AT 108.3 TPY: 145-02-A, 145-02-B, 145-02-C, 145-02-D, 145-02-E, 145-02-F, 145-02-G, 145-02-H, 145-02-I, 145-02-J, 145-02-K, 145-02-L, 145-02-M, 145-02-N, 145-02-O, & 145-02-P.
WA-0343	BP WEST COAST PRODUCTS LLC	BP CHERRY POINT REFINERY	2911	WHATCOM	WA	NO. PSD 07-01	11/17/2007	UTILITY AND LARGE INDUSTRIAL SIZE BOILERS/FURNACES	REFINERY GAS	363	MMBTU/H	PM10	3.4000 LB/H CALENDAR DAY			BURN ONLY REFINERY FUEL GAS/NATURAL GAS	BACT-PSD	PM10 EMISSIONS ESTIMATED USING EMISSION FACTOR BASED ON BP STACK TESTING ON SIMILAR BOILERS BURNING RFG. EMISSSION FACTOR IS 12.74 LB OF TOTAL PARTICULATE (FILTERABLE PLUS CONDENSABLE) PER MILLION STANDARD CUBIC FEET OF RFG COMBUSTED.
TX-0288	AIR LIQUIDE AMERICA CORPORATION	AIR LIQUIDE- FREEPORT HYCO	2813	BRAZORIA	TX	PSD-TX-995	6/22/2001	STEAM METHANE REFORMER (SMR) STACK	H2 OFF GAS*	286	MMBTU/H	PM	3.3000 LB/H	14.4600 T/YR		None	None	
								AUXILIARY BOILER STACK	H2 OFF-GAS*	400.00	MMBTU/H	PM	8.0000 LB/H	35.0400 T/YR	0.0200 LB/MMBTU CALCULATED	None	NSPS	EMISSION LIMIT IN STANDARDIZED UNITS CALCULATED BY DIVIDING HOURLY EMISSION LIMIT BY THROUGHPUT.
OH-0317	OHIO RIVER CLEAN FUELS, LLC	OHIO RIVER CLEAN FUELS, LLC	2869	COLUMBIANA	OH	02-22896	11/20/2008	GAS FIRED HEATERS (3)	NATURAL GAS AND TAIL GAS	4	MMBTU/H	PM10	0.0900 LB/H FOR EACH OF 3 GAS HEATERS	0.4000 T/YR PER ROLLING 12-MONTH PERIOD	7.6000 LB/MMSCF AP-42 FACTOR	None	NSPS, SIP	LIMITS ARE FOR EACH OF THE 3 GAS HEATERS.
								BOILER	NATURAL GAS AND TAIL GAS	1200	MMBTU/H	PM10	18.7000 LB/H AS A 3-HOUR AVERAGE	81.9000 T/YR PER ROLLING 12-MONTH PERIOD	0.0156 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-PSD, SIP	
AZ-0046	ARIZONA CLEAN FUELS YUMA LLC	ARIZONA CLEAN FUELS YUMA	2911	YUMA	AZ	1001205	4/14/2005	CATALYTIC REFORMING UNIT CHARGE HEATER	REFINERY FUEL GAS AND NATURAL GAS	122	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVG.			None	BACT-PSD	
								BUTANE CONVERSION UNIT DEHYDROGENATION REACTOR CHARGE HEATER	REFINERY FUEL GAS AND NATURAL GAS	311.00	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVERAGE		0.0075 LB/MMBTU	None	BACT-PSD	
								VACUUM CRUDE CHARGE HEATER	REFINERY FUEL GAS AND NATURAL GAS	101	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVERAGE		0.0075 LB/MMBTU	None	BACT-PSD	
								HYDROCRACKER UNIT CHARGE HEATER	REFINERY FUEL GAS AND NATURAL GAS	70	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVERAGE		0.0075 LB/MMBTU	None	BACT-PSD	
								HYDROGEN REFORMER HEATER	REFINERY FUEL GAS AND NATURAL GAS	1435.00	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVERAGE		0.0075 LB/MMBTU	None	BACT-PSD	
								SPRAY DRYER HEATER	REFINERY FUEL GAS AND NATURAL GAS	44	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVERAGE		0.0075 LB/MMBTU	None	BACT-PSD	
								DISTILLATE HYDROTREATER SPLITTER REBOILER	REFINERY FUEL GAS AND NATURAL GAS	117.00	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVERAGE		0.0075 LB/MMBTU	None	BACT-PSD	
								CATALYTIC REFORMING UNIT INTERHEATER NO. 2	REFINERY FUEL GAS AND NATURAL GAS	129	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVERAGE		0.0075 LB/MMBTU	None	BACT-PSD	
								ATMOSPHERIC CRUDE CHARGE HEATER	REFINERY FUEL GAS AND NATURAL GAS	346	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVERAGE		0.0075 LB/MMBTU	None	BACT-PSD	
								DELAYED COKING UNIT CHARGE HEATER NOS. 1 AND 2	REFINERY FUEL GAS AND NATURAL GAS	99.5	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVERAGE		0.0075 LB/MMBTU	None	BACT-PSD	
								CATALYTIC REFORMING UNIT INTERHEATER NO. 1	REFINERY FUEL GAS AND NATURAL GAS	192	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVERAGE		0.0075 LB/MMBTU	None	BACT-PSD	
								CATALYTIC REFORMING UNIT DEBUTANIZER REBOILER	REFINERY FUEL GAS AND NATURAL GAS	23.2	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVERAGE			None	BACT-PSD	
								BUTANE CONVERSION UNIT ISOSTRIPPER REBOILER	REFINERY FUEL GAS AND NATURAL GAS	222	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVERAGE		0.0075 LB/MMBTU	None	BACT-PSD	
								BUTANE CONVERSION UNIT DEHYDROGENATION REACTOR INTERHEATER	REFINERY FUEL GAS AND NATURAL GAS	328	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVERAGE		0.0075 LB/MMBTU	None	BACT-PSD	
								HYDROCRACKER UNIT MAIN FRACTIONATOR HEATER	REFINERY FUEL GAS AND NATURAL GAS	211	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVERAGE		0.0075 LB/MMBTU	None	BACT-PSD	
								DISTILLATE HYDROTREATER CHARGE HEATER	REFINERY FUEL GAS AND NATURAL GAS	25	MMBTU/H	PM10	0.0075 LB/MMBTU 3-HR AVERAGE		0.0075 LB/MMBTU	None	BACT-PSD	
								NAPHTHA HYDROTREATER CHARGE HEATER	REFINERY FUEL GAS AND NATURAL GAS	21.40	MMBTU/H	PM11	0.0075 LB/MMBTU 3-HR AVERAGE		0.0075 LB/MMBTU	None	BACT-PSD	

RACT/BACT/LAER Clearinghouse
Results for Decoke Units (PM_{10}, $PM_{2.5}$)

RBCL ID	Facility	Facility Description	SIC Code	County/ Parish	State	Permit Number	Permit Date	Process	Primary Fuel	Throughput	Throughput Unit	Pollutant	Emission Limit 1	Emission Limit 2	Standard Emission	Control Description	Efficiency	Basis	Comments
TX-0339	EXXON MOBIL CHEMICAL COMPANY	OLEFINS PLANT Cracking Furnace	2869	HARRIS	TX	PSD-TX-302 (M2)	04/05/2001 (actual)	DECOKING STACK AF-01				PM	11.4000 LB/H	1.4000 T/YR		None		Other Case-by-Case	
								DECOKING STACK AF-01				VE		10% opacity 6 min avg		None			
								DECOKING STACK BF-01				PM	2.6000 LB/H	0.3100 T/YR		None		Other Case-by-Case	
								DECOKING STACK BF-01				VE		10% opacity 6 min avg		None			
								DECOKING STACK CF-01				PM	10.4000 LB/H	1.2000 T/YR		None		Other Case-by-Case	
												VE		10% opacity 6 min avg		10% opacity 6 min avg			
								(4) DECOKING STACKS, DF-01 THRU GF-01				PM	8.5000 LB/H EACH	1.0000 T/YR EACH		Wet Cyclone		Other Case-by-Case	
												VE		10% opacity 6 min avg		Wet Cyclone			
								DECOKING STACK HF-01				PM	11.4000 LB/H	1.4000 T/YR		None		Other Case-by-Case	
												VE		10% opacity 6 min avg		None			
								(2) DECOKING STACKS IF-01 & JF-01				PM	20.4000 LB/H EACH	1.0000 T/YR EACH		None		Other Case-by-Case	
												VE		10% opacity 6 min avg		None			
								(2) DECOKING STACKS, OF-01 & QF-01				PM	14.6000 LB/H EACH	0.9200 T/YR EACH		None		Other Case-by-Case	
												VE		10% opacity 6 min avg		None			
								(6) DECOKING STACKS XAF-01 THRU XFF-01				PM	14.6000 LB/H EACH	0.7700 T/YR EACH		None		Other Case-by-Case	
												PM	34.9000 LB/H	1.5000 T/YR		Wet Cyclone			
								DECOKING STACK XGF-01				PM10	19.9000 LB/H	0.8000 T/YR		Wet Cyclone		Other Case-by-Case	
TX-0475	FORMOSA PLASTICS CORPORATION TEXAS	COMFORT PLANT PYROLYSIS CRACKING FURNACE	2821	CALHOUN	TX	19168 / PSD-TX-760M6	05/09/2005 (actual)	DECOKE DRUM (5) for Pyrolysis Furnace				PM10	7.0500 LB/H	1.6200 T/YR		None		NA	
TX-0347	BP AMOCO CHEMICAL COMPANY	PETROCHEMICAL MANUFACTURING, OLEFINS CRACKING FURNACES	2869	BRAZORIA	TX	PSD-TX-854	10/16/2001 (actual)	DECOKE STACK, DF-101				PM10	0.2900 LB/H	0.1800 T/YR		(A) CYCLONE SEPARATOR	90%	BACT-PSD	
								DECOKE STACK, DDF-101				PM10	6.2000 LB/H	1.5000 T/YR		(A) CYCLONE SEPARATOR	90%	BACT-PSD	
								DECOKE STACK DF-104				PM10	0.7400 LB/H	0.0200 T/YR		(A) CYCLONE SEPARATOR	90%		
								DECOKE STACK, DDF-104				PM10	0.8000 LB/H	0.0200 T/YR		(A) CYCLONE SEPARATOR	90%	BACT-PSD	
								(2) DECOKE STACKS, DF-105 & DDF-105				PM10	8.2500 LB/H	0.8300 T/YR		(A) CYCLONE SEPARATOR	90%	BACT-PSD	
LA-0213	VALERO REFINING - NEW ORLEANS, LLC	PETROLEUM REFINERY. PROJECT INVOLVES INCREASE IN CAPACITY FROM 220,000 TO 380,000 BARRELS PER DAY.		ST. CHARLES	LA	PSD-LA-619(M5)	11/17/2009	FLUIDIZED CATALYTIC CRACKING UNIT DECOKE	PETROLEUM	84200.00	LB/H COKE BURN-OFF	PM10	331.9200 T/YR ROLLING 365-DAY SUM OF DAILY EMISSIONS	0.9000 LB/ 1000 LB COKE	0.9000 LB/ 1000 LB COKE	(A) WET GAS SCRUBBER	95%	BACT-PSD	
								FLUIDIZED CATALYTIC CRACKING UNIT DECOKE	PETROLEUM	84200.00	LB/H COKE BURN-OFF	PM	0.4500 LB/1000 LB PER 1000 POUNDS OF COKE BURNOFF	165.9600 T/YR		(A) WET GAS SCRUBBER	95%	BACT-PSD	
WA-0324	CONOCOPHILLIPS REFINING COMPANY FERNDALE REFINERY	REFINING INCREASE THROUGHPUT OF FCCU	2911	WHATCOM	WA	PSD-00-02 AMENDMENT 3	06/15/2005 (actual)	FCC & CO BOILER	REFINERY GAS			PM10	0.5000 LB/1000 LB COKE BURN THREE-HOUR AVERAGE	0.0200 G/DSCF 7 % OXYGEN OVER A ROLLING 3-HOUR AVERAGE	0.012 LB/MMBTU CALCULATED	(A) WET GAS SCRUBBER	MOVE TO DECOKE	Other Case-by-Case	BY NO LATER THAN DECEMBER 31, 2006, COMBINED PM/PM10 EMISSIONS FROM THE FCCU AND CO BOILER SHALL NOT EXCEED 0.50 LB/1000 LBS COKE BURN-OFF OVER A ROLLING THREE-HOUR AVERAGE AND 0.020 GRAINS PER DRY STANDARD CUBIC FOOT CORRECTED TO 7% OXYGEN OVER A ROLLING 3-HOUR AVERAGE. INITIAL COMPLIANCE SHALL BE DETERMINED IN ACCORDANCE WITH EPA REFERENCE METHOD 5B

RACT/BACT/LAER Clearinghouse
Results for Decoke Units (CO_2)

RBCL ID	Facility	Facility Description	SIC Code	County/ Parish	State	Permit Number	Permit Date	Process	Primary Fuel	Throughput	Throughput Unit	Pollutant	Emission Limit 1	Emission Limit 2	Control Description	Effeciency	Basis	Comments
TX-0347	BP AMOCO CHEMICAL COMPANY	PETROCHEMICAL MANUFACTURING, OLEFINS CRACKING	2869	BRAZORIA	TX	PSD-TX-854	10/16/2001 (actual)	DECOKE STACK, DDF-101				Carbon Dioxide	36.5000 LB/H	7.2000 T/YR	None Indicated		BACT-PSD	
TX-0550	BASF FINA PETROCHEMICALS LIMITED PARTNERSHIP	OLEFINS COMPLEX	2869	JEFFERSON	TX	36644	02/10/2010 (actual)	N-18, DECOKING DRUM Petroleum refining conversion process (cracking, reforming, etc.)	METHANE	26625	LB COKE/CYCLE	Carbon Dioxide			Good combustion practices		BACT-PSD	THE RACT/BACT/LAER DATABASE WAS SEARCHED FOR THIS FACILITY TYPE AND SIMILAR PROCESSES WERE FOUND BUT THERE WERE NO PROJECT NOTES. THE DECOKING DRUM AND FURNACE TUBES ARE HEATED AND ANY COKE PRESENT ON THE CATALYST IS CONVERTED TO CO OR CO2. UNIT USED GOOD COMBUSTION PRACTICES TO MEET BACT. SINCE GOOD COMBUSTION PRACTICES ARE GOOD BUSINESS PRACTICE, NO ADDITIONAL CONDITIONS OR MONITORING WERE REQUIRED FOR THIS AMENDMENT.
								N-10, CATALYST REGENERATION EFFLUENT	METHANE	2100.00	CFS	Carbon Dioxide			Good combustion practices		BACT-PSD	THE RACT/BACT/LAER (RBLC) DATABASE WAS SEARCHED FOR THIS FACILITY TYPE. A MARATHON PETROLEUM DETROIT REFINERY CATALYST REGENERATION UNIT AND A BP WEST COAST PRODUCTS CATALYST REGENERATION UNIT USED GOOD COMBUSTION PRACTICES TO MEET BACT. THESE WERE THE ONLY FACILITIES LISTED IN THE RBLC DATABASE FOR THIS FACILITY TYPE. GOOD COMBUSTION PRACTICES ARE USED FOR EPN N-10.THE CATALYST FROM THE ACETYLENE CONVERTER MAIN BEDS, ACETYLENE CONVERTER GUARD BED, METHYL ACETYLENE, PROPADIENE CONVERTERS, C4 DIOLEFIN HYDROGENATION REACTOR AND FIRST STAGE DIOLEFINS REACTOR IS HEATED AND ANY COKE PRESENT ON THE CATALYST IS CONVERTED TO CO OR CO2. SINCE GOOD COMBUSTION PRACTICES ARE GOOD BUSINESS PRACTICE, NO ADDITIONAL CONDITIONS OR MONITORING WERE REQUIRED FOR THIS AMENDMENT
								N-11, REACTOR REGENERATION EFFLUENT Petroleum refining conversion process (cracking, reforming, etc.	METHANE	5064.83	CFS	Carbon Dioxide			Good combustion practices		BACT-PSD	THE RACT/BACT/LAER DATABASE WAS SEARCHED FOR THIS FACILITY TYPE AND NO EXACT PROCESS WAS FOUND. THE MSS PROCESS AT N-11 IS SIMILAR TO N-10, THE CATALYST FROM THE DP REACTOR IS HEATED AND ANY COKE PRESENT ON THE CATALYST IS CONVERTED TO CO OR CO2. UNIT USED GOOD COMBUSTION PRACTICES TO MEET BACT SINCE GOOD COMBUSTION PRACTICES ARE GOOD BUSINESS PRACTICE, NO ADDITIONAL CONDITIONS OR MONITORING WERE REQUIRED FOR THIS AMENDMENT

TCEQ CHEMICAL SOURCES
CURRENT BEST AVAILABLE CONTROL TECHNOLOGY (BACT) REQUIREMENTS

Equipment Leak Fugitives

This information is maintained by the CHEMICAL NSR Section and is subject to change. Last update 10/17/2006.

Year	Source Type	Pollutant	Minimum Acceptable Control	Control Efficiency or Details
2006	Equipment Leak Fugitives	Uncontrolled VOC emissions < 10 tpy	None	
		10 tpy < uncontrolled VOC emissions < 25 tpy	28M leak detection and repair program	75% credit for 28M
		Uncontrolled VOC emissions > 25 tpy	28VHP leak detection and repair program	97% credit for valves, 85% for pumps and compressors
		VOC vp < 0.002 psia	No inspection required	No fugitive emissions expected
		Approved odorous compounds: NH3, Cl2, H2S, etc.	Audio/Visual/Olfactory (AVO) inspection twice per shift	Appropriate credit for AVO program

Appendix E | TCEQ VHP Sample Special Conditions

Texas Commission on Environmental Quality
Air Permits Division

New Source Review (NSR) Boilerplate Special Conditions

This information is maintained by the Chemical NSR Section and is subject to change. Last update was made **October 2006**. These special conditions represent current NSR boilerplate guidelines and are provided for informational purposes only. The special conditions for any permit or amendment are subject to change through TCEQ case by case evaluation procedures [30 TAC 116.111(a)]. Please contact the appropriate Chemical NSR Section management if there are questions related to the boilerplate guidelines.

<u>Piping, Valves, Connectors, Pumps, and Compressors in Volatile Organic Compounds (VOC) Service - 28VHP</u>

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 pounds per square inch, absolute (psia) at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made available upon request.

   The exempted components may be identified by one or more of the following methods:

   i. piping and instrumentation diagram (PID); or
   ii. a written or electronic database.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), shall be identified in a list to be made available upon request. The non-accessible valves may be identified by one or more of the methods described in subparagraph A above.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 8 hours of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed. If the removal of a component for repair or replacement results in an open-ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 24 hours. If the repair or replacement is not completed within 24 hours, the line or valve must have a cap, blind flange, plug, or second valve installed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Method 21 of 40 CFR part 60, appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section 8 of Method 21. If a mixture of VOCs are being monitored, the response factor shall be calculated for the average composition of the process fluid. If a response factor less than 10 cannot be achieved using methane, than the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured.

Replacements for leaking components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump, compressor, and agitator seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 parts per million by volume (ppmv) or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump, compressor, and agitator seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired.

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown, the TCEQ Executive Director or designated representative shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown.

J. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections shall be noted in the operator's log or equivalent.

K. Alternative monitoring frequency schedules of 30 TAC §§ 115.352 - 115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR Part 63, Subpart H, may be used in lieu of Items F through G of this condition.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS) and does not constitute approval of alternative standards for these regulations.

Appendix F | An ENERGY STAR Guide for Energy and Plant Managers

LBNL-964E

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry

An ENERGY STAR® Guide for Energy and Plant Managers

Maarten Neelis, Ernst Worrell, and Eric Masanet

Environmental Energy Technologies Division

Sponsored by the U.S. Environmental Protection Agency

June 2008

8. Furnaces / Process Heaters

Approximately 30% of the fuel used in the chemical industry is used in fired heaters. The average thermal efficiency of furnaces is estimated at 75-90% (Petrick and Pellegrino, 1999). Accounting for unavoidable heat losses and dewpoint considerations the theoretical maximum efficiency is around 92% (HHV) (Petrick and Pellegrino, 1999). This suggests that typical savings of 10% can be achieved in furnace and burner design, and operations. In the following section, various improvement opportunities are discussed, including improving heat transfer characteristics, enhancing flame luminosity, installing recuperators or air-preheaters and improved controls. New burner designs aim at improved mixing of fuel and air and more efficient heat transfer. Many different concepts are developed to achieve these goals, including lean-premix burners (Seebold et al., 2001), swirl burners (Cheng, 1999), pulsating burners (Petrick and Pellegrino, 1999) and rotary burners (U.S. DOE-OIT, 2002c). At the same time, furnace and burner design has to address safety and environmental concerns. The most notable is the reduction of NOx emissions. Improved NOx control will be necessary in many chemical industries to meet air quality standards.

Heat generation. In heat generation, chemical or electrical energy is converted into thermal energy. A first opportunity to improve the efficiency of heat generation is to control the air-to-fuel ratio in furnaces. Badly maintained process heaters may use excess air. This reduces the efficiency of the burners. Excess air should be limited to 2-3% oxygen to ensure complete combustion. Typical energy savings of better controlled air to fuel ratios vary between 5 and 25% (U.S. DOE-OIT, 2004c). The use of up-to-date exhaust gas oxygen analyzer can help to maintain optimal air-to-fuel ratios. At the Deer Park facility of Rohm and Haas, old exhaust oxygen analyzers resulted in delayed reading and made it more difficult to accurately monitor combustion conditions. Installation of three new analyzers in the furnace ducts resulted in real-time readings of oxygen levels and better process control (U.S. DOE-OIT, 2006d). Typical payback times of projects aiming to reduce combustion air flows by better control are around 6 months or less (IAC, 2006).

In many areas new air quality regulation will demand industries to reduce NOx and VOC emissions from furnaces and boilers. Instead of installing expensive selective catalytic reduction (SCR) flue-gas treatment unit's new burner technology allows to reduce emissions dramatically. This will result in cost savings as well as help to decrease electricity costs for the SCR. In a plant-wide assessment of a Bayer Polymers plant in New Martinsville, West Virginia (U.S. DOE-OIT, 2003d), the replacement of natural gas and hydrogen fuelled burners with efficient low NO_x design burners was identified as a project that could result in 2% efficiency improvements saving 74,800 MMBtu per year and annual CO_2 emission reductions of 8.46 million pounds. Estimated pay-back time for the project was 13 months at total project costs of $ 390,000. Efficient use of existing burners can also help to save energy and reduce NO_x emissions. In an energy-efficiency assessment of the Anaheim, California site of Neville Chemical Company (U.S. DOE-OIT, 2003e), a potential project was identified in which only a single natural gas fuelled incinerator (instead of the two operated) can be used to incinerate Volatile Organic Compounds (VOCs). This would result in energy savings of 8 TBtu per year. Project costs were estimated at $57,500 with a payback period of 1.3 years.

Heat transfer and heat containment in heaters. Improved heat transfer within a furnace, oven or boiler can result in both energy savings and productivity gains. There can be several ways to improve heat transfer such as the use of soot blowers, burning off carbon and other deposits from radiant tubes and cleaning the heat exchange surfaces. Typical savings are 5-10% (U.S. DOE-OIT, 2004c). Ceramic coated furnace tubes can improve heat transfer of metal process tubing, while stabilizing the process tube's surface. They can improve energy efficiency, increase throughput or both. Increased heat transfer is accomplished by eliminating the insulating layers on the fire-side of process tubing that form during operation. Applications in boilers and petrochemical process units have shown efficiency improvements between 4% and 12% (Hellander, 1997). Heat containment can be improved by numerous measures, including reducing wall heat losses (typical savings 2-5%), furnace pressure control (5-10%), maintenance of door and tube seals (up to 5%), reducing cooling of internal parts (up to 5%) and reducing radiation heat losses (up to 5%). Typical payback times of project aiming to reduce heat losses and improved heat transfer are between 3 months and 1 year (IAC, 2006).

Flue gas heat recovery. Reducing exhaust losses (e.g. by the measures described above) should always be the first concern in any energy conservation program. Once this goal has been met, the second level should be considered – recovery of exhaust gas waste heat. Use of waste heat to preheat combustion air is commonly used in medium to high temperature furnace. It is an efficient way of improving the efficiency and increasing the capacity of a process heater. The flue gases of the furnace are used to preheat the combustion air. Every 35°F drop in the exit flue gas temperature increases the thermal efficiency of the furnace by 1% (Garg, 1998). Typical fuel savings range between 8 and 18%, and is typically economically attractive if the flue gas temperature is higher than 650°F and the heater size is 50 MMBtu/hr or more (Garg, 1998). The optimum flue gas temperature is also determined by the sulfur content of the flue gases to reduce corrosion. When adding a preheater the burner needs to be re-rated for optimum efficiency. Energy recovery can also be applied in catalytic oxidizers used to reduce volatile organic compound (VOC) emissions, e.g. via a regenerative heat exchanger in the form of a ceramic packing (Hydrocarbon Processing, 2003).

Heat from furnace exhaust gases or from other sources (discussed in Chapter 9) can also be used in waste heat or quench boilers to produce steam (discussed in Chapter 7) or to cascade heat to other applications requiring lower temperature heat as part of the total plant heat demand and supply optimization (see also Chapter 9 on process integration). Recovering thermal energy in the form of steam from incineration of waste products should be considered carefully. Because a waste stream is used, the stream will have variations in contaminant and component concentrations which influence to load on the boiler. Also, the contaminants might create acid gases causing corrosion problems for the boiler. These aspects should be taken into account in designing waste heat boilers (Ganapathy, 1995).

The benefits from heat recovery projects have been shown in various case studies. In an energy-efficiency assessment of the 3M Hutchinson, Minnesota, facilities, heat recovery from thermal oxidizers in the form of low-pressure steam was identified as a project that could save 210,000 MMBtu of fuels (U.S. DOE-OIT, 2003f). Project capital costs are $913,275 with avoided first year energy expenses of $772,191. In an audit of the W.R. Grace facility in

Curtis Bay, Baltimore, Maryland, a project was identified that uses flue gas heat in an air-to-water heat exchanger for fresh water heating, reducing the original steam demand for heating this water by 31%. Capital costs for this project are estimated at $346,800 with a relatively long payback period of 5.3 years (U.S. DOE-OIT, 2003g). In a project in the UK, heat recovery from an incinerator via a run-around coil system yielded energy savings of 9 TBtu per year with a payback time of 1.5 years (Best Practice Programme, 1991). Heat recovery from the SO_2 containing gases of a sulphur burning process in a sulphonation plant in Norway resulted in energy savings of 4,800 MWh per year (CADDETT, 2000b). Investment costs were $800,000 and the simple payback time of the project 6 years.

Others – controls, maintenance and electric heaters. Energy losses can also be reduced via improved process control. Improved control systems can help to improve aspects such as material handling, heat storage and plant turndown. Typical savings of improved control systems can be in the range of 2-10% (U.S DOE-OIT, 2004c). A relatively small part of the heating requirements in the chemical industry is supplied by electrically heated devices. Still, electric heaters account for approximately 3% of the electricity use of the chemical industry (U.S. DOE-OIT, 2006a). Not in all cases, electric heating is the right choice (Best Practice Programme, 2001) and in a number of cases, improvements are possible. For example, in an energy-efficiency assessment of the Anaheim, California site of Neville Chemical Company (U.S. DOE-OIT, 2003e), a potential project was identified in which electric heaters are to be replaced with a natural-gas fired heat fired system, using 557 MMBtu per year, but replacing 114,318 kWh of electricity. Project costs for the project were estimated at $6,100 with a payback time of 0.9 years. In an assessment of a Formosa Plastics Corporation polyethylene plant (U.S. DOE-OIT, 2005a), improvement of an electrically heated extruder was identified as a project that could result in electricity savings of 1,488,000 kWh annually, resulting in annual cost savings of $59,520. The estimated payback time for the projects was 0.1 year.