OXY Occidental Chemical Corporation OxyChem.
A subsidiary of Occidental Petroleum Corporation

P. O. Drawer CC, Ingleside, Texas 78362-0710
Hwy 361, Gregory, Texas 78359
Phone 361.776.6050 Fax 361.776.6240

Health Environmental Safety Department

December 21, 2012

Ms. Aimee Wilson
Air Permits Section (6PD-R)
U.S. Environmental Protection Agency
1445 Ross Avenue
Dallas, TX 75202

Re: Federal Prevention of Significant Deterioration Permit Application
Ethylene Plant
Ingleside Chemical Plant
Gregory, San Patricio County
TCEQ Account ID No. SD-0092-F
TCEQ Regulated Entity No. 100211176
TCEQ Customer Reference No. 600125256

Dear Ms. Wilson:

Enclosed please find an application for the authorization of a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gases (GHG) from the proposed new Ethylene Plant to be located at the referenced site.

A similar PSD application addressing the criteria pollutants for this project was submitted to the Texas Commission on Environmental Quality (TCEQ). In order to facilitate a better understanding of these parallel permitting processes, you were copied on this TCEQ application.

As discussed in a previous meeting with EPA staff members regarding a similar application, TCEQ forms are used to convey relevant permit information. In some cases, these TCEQ forms are slightly modified to more clearly represent GHG issues.

Occidental Chemical Corporation is interested in proceeding with the timely processing of this application. If there are any questions, please feel free to call me at (361) 776-6169 or Stuart Keil, P.E., at (512) 306-9983.

Sincerely,

Mark Evans

Mark R. Evans
Environmental Manager

MRE:see/T1HH556W

Enclosures

cc: Mr. Stuart L. Keil, P.E., Keil Environmental, Inc., Austin, w/enclosures

THE U.S. ENVIRONMENTAL PROTECTION AGENCY
FEDERAL PREVENTION OF SIGNIFICANT
DETERIORATION PERMIT APPLICATION

OCCIDENTAL CHEMICAL CORPORATION

INGLESIDE CHEMICAL PLANT, SAN PATRICIO COUNTY
TCEQ ACCOUNT ID NO. SD-0092-F
TCEQ CUSTOMER NO. 600125256
TCEQ REGULATED ENTITY NO. 100211176

ETHYLENE PLANT

December 2012

Submitted by:

Mark R. Evans
Environmental Manager
Occidental Chemical Corporation

STATE OF TEXAS
STUART L. KEIL
50683
LICENSED
PROFESSIONAL ENGINEER

12/17/12

Prepared by:

Stuart L. Keil, P.E.
Keil Environmental, Inc.
TBPE Registration No. F-4725

Occidental Chemical Corporation
December 2012

TABLE OF CONTENTS

INTRODUCTION

Occidental Chemical Corporation (OxyChem) is proposing to construct and operate a new 1.2 billion pound per year Ethylene Plant at its existing site near Ingleside, Texas on land immediately adjacent to the existing Vinyl Chloride Monomer (VCM) Plant. The new Ethylene Plant will receive ethane feed from a planned Natural Gas Liquids (NGL) Fractionation Plant to be constructed on adjacent property or by pipeline. The Ethylene Plant will produce market grade ethylene which will be transported by pipeline as feed material to the existing VCM Plant or to other markets.

It should be noted that this Ethylene Plant constitutes a major modification and is subject to federal prevention of significant deterioration (PSD) review for the following pollutants: volatile organic compounds, nitrogen oxides, carbon monoxide, particulate matter, particulate matter less than 10 microns, particulate matter less than 2.5 microns and greenhouse gases (GHGs). All of these PSD pollutants except for GHG are addressed in a separate application submitted to the TCEQ this December. This application is only intended to authorize the proposed facilities relative to GHG emissions.

A general application and GHG PSD applicability forms for these proposed facilities are provided in Appendix A, General Application and PSD Applicability Forms.

ETHYLENE PLANT PROCESS DESCRIPTION

The ethane feed to the Ethylene Plant is combined with recycle ethane from the ethylene fractionator and superheated with water before being sent to the cracking furnaces. The cracking furnaces will be equipped with selective catalytic reduction (SCR) technology for NO_x control. The ethane is fed to five cracking furnaces to heat the ethane to cracking temperature.

To reduce coke formation in the cracking furnace tubes, a sulfide material is added continuously to the ethane feed. The concentration of sulfide material in the ethane feed is maintained at low ppm levels. Two chemicals may be used for this purpose, dimethyl disulfide (DMDS) or dimethyl sulfide (DMS). The sulfide chemical is stored in a pressurized tank and truck off-loading of the material is accomplished using vapor balancing with the delivery truck.

The effluent from cracking furnaces is used to produce high pressure steam in transfer line exchangers (TLE's) before being quenched in the quench tower. The cracked gas from the TLE's is cooled and partially condensed by direct countercurrent contact with recirculating water in the quench tower. The condensed gasoline and dilution steam, along with quench water, are separated in the bottom section of the quench tower and the non-condensable gas exits the top of the quench column.

The quench tower overhead vapor is sent to the first stage of the steam driven charge gas compressor where the vapors are compressed in a three stage centrifugal compressor. Acid gases are removed from the charge gas in the third stage compressor discharge. The acid gas removal consists of a three stage caustic wash tower. Charge gas from the caustic wash tower overhead is chilled in the dryer feed chiller system. Charge gas from the dryer feed chiller system overhead is dried in a molecular sieve drying system.

The vapor from the charge gas dryer is chilled before entering the front-end de-ethanizer . The de-ethanizer tower produces a vapor overhead product with primarily C2 and lighter content and a bottoms product that is stripped of ethane and lighter components. Acetylene is removed from the de-ethanizer overhead by selective hydrogenation to ethylene and ethane. The de-ethanizer overhead product is then chilled and sent to the de-methanizer.

The overhead of the de-methanizer consists of methane and hydrogen. This hydrogen-rich vapor from the de-methanizer is processed to separate hydrogen for use in the hydrogenation reactors and the balance is used as fuel gas. De-methanizer bottoms are fed to the ethylene fractionator. The ethylene fractionator overhead vapor is condensed as ethylene product that is sent out by pipeline or to the adjacent VCM plant. The ethylene fractionator bottoms are predominantly ethane and this stream is returned to the cracking furnace feed.

The de-ethanizer bottoms product is sent to the de-butanizer to separate the C3's and C4's from the C5+ gasoline. The debutanizer bottoms product is sent to C5 gasoline storage. The de-butanizer overhead product is hydrotreated in the hydrogenation reactor to convert diolefins and olefins into normal propane and butane. The propane/butane mix stream from the hydrogenation reactor is returned to the NGL Fractionation Plant as feed.

One of the byproducts of the ethylene plant is a stream called pyrolysis gasoline. This material is sold to petroleum refineries as a gasoline blend stock. The pyrolysis gasoline will be loaded into trucks for transportation to the refinery customers. The vents from loading these trucks are routed to the cracker thermal oxidizers for VOC control.

A propylene refrigeration system, which utilizes a steam turbine-driven centrifugal compressor, provides refrigeration at four levels of temperature. A binary refrigerant system uses methane and ethylene to provide the coldest level of refrigeration in the plant for cooling and condensing process streams at three additional levels.

Spent caustic from the caustic tower is treated in a wet air oxidizer system to oxidize sulfides and other chemical oxidation demand before being discharged to the wastewater treatment plant.

A six cell cooling tower will be used to remove the heat from the process by thermal exchange.

Low pressure discharges of vent gases from process equipment and storage vessels are collected in dedicated headers and transferred to a thermal oxidizer for disposal. A back-up enclosed, low pressure flare is provided for emissions control in the unlikely event of thermal oxidizer failure. The two thermal oxidizers are designed to destroy and remove organic materials from the collected vent gases with an efficiency of 99.9%. They are supplied with natural gas to ensure complete combustion with minimum production of carbon monoxide.

An additional flare system provides a means to collect and burn hydrocarbon process streams that have relieved or been drained to the flare headers. The emergency relief collection and transfer systems discharge to a multi-point low profile, high pressure ground flare with a staged burner control system. A heat radiation shielding fence will minimize the radiation to the acceptable level outside the fence and avoid production of a visible flame. Numerous pilots, supplied with natural gas, are provided to ensure that any emergency relief will be ignited.

Process wastewaters, contaminated storm water, surface wash down and other wastewaters are collected in process area sumps which pump to wastewater storage tanks. The wastewater storage tank is vented to the thermal oxidizers. Wastewater from the wastewater storage tank is sent to the wastewater steam stripper to remove volatile organic compounds prior to treatment in an activated sludge treatment system within the VCM Plant.

A summary of storage tanks is provided as follows:

1) Pressure tanks: 90,000 gal propylene tank; 600,000 gal C3/C4 tank; 10,000 gal anhydrous ammonia tank; 10,000 gal DMS/DMDS tank
2) Low pressure tanks venting to the oxidizers: three 1,100,000 gal contaminated water tanks; two 150,000 gal pyrolysis gasoline tanks; 50,000 gal heavy oil tank; 150,000 gal collected

oil tank; 20,000 gal wash oil tank; two 150,000 gal caustic tanks

3) Atmospheric tanks: 10,000 gal methanol tank (PBR 106.473); 10,000 gal sulfuric acid tank (PBR 106.472)

A process flow diagram for the new Ethylene Plant is provided in Appendix B, Area Map, Plot Plan and Other Supporting Documents. This appendix includes a plot plan, area map and other documents requested in Section VII of the Form PI-1.

PROPOSED GREENHOUSE GAS (GHG) EMISSIONS

Emission calculations for maximum hourly and annual rates are provided in Appendix C, Emission Calculations. This emissions data includes the basis for the calculations, the emission factors, the sources of the factors, pollutant specific estimates and calculation methods.

The GHG emissions calculated for these sources include the following: carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). The reported emissions in Appendix C include the use of the appropriate global warming potential factors to express these GHG emissions as carbon dioxide equivalents (CO_2e).

The new sources proposed for the Ethylene Plant are identified as follows: five cracking furnaces, two thermal oxidizers, a high pressure ground flare, an emergency generator engine, a low pressure enclosed flare, a cooling tower and fugitive sources identified for six operating areas. In addition, intermittent emissions are expected from the C3/C4 hydrogenation regeneration vent. GHG emissions are expected from all of these sources except for two of the six fugitive areas.

It should be noted that the existing cogeneration facilities at the site are also considered affected sources for GHG permitting purposes. Appendix C includes estimated emission increases for all of the ethylene production facilities, including the cogeneration units.

These cogeneration units are not being modified and their increased fuel firing will not exceed previously authorized levels (see Permit Nos. 35335 and PSD-TX-880). However, for the purpose of the current permit review, these cogeneration units are considered by the EPA to be affected sources that should be used to determine the applicability of federal PSD permitting.

EPN's CR-1 through CR-5; Ethane Cracking Furnaces Nos. 1 through 5

The ethane cracking furnaces for the proposed facilities include five identical combustion units expected to fire natural gas and hydrogen-rich fuel gas at a maximum rate of 275 MM Btu/hr. Typically, four of these units will be operating while the fifth unit is being serviced or held on stand-by. However, at times, all five units may be running at full capacity.

Normal operation involves natural gas and/or process-related fuel gas (high hydrogen gas) firing in the furnaces and the control of NO_x emissions using SCR. Three additional operating scenarios are described below that pertain to furnace maintenance, start-up and shutdown (MSS) activities.

During normal operations, furnaces will be operated using process generated fuel gas which is a combination of hydrogen, methane, ethane, and heavier hydrocarbons. During this operation, the heat input to the fire box is maintained to achieve the desired cracking rate. Ethane and steam are fed to the furnace tube inlets and the furnace outlet is routed to the quench tower where the process gases are cooled.

It should be noted that normal operations can include firing only natural gas without the process fuel gas, and so, this scenario is included in the Appendix C emission calculations. Firing with natural gas represents worst-case emissions for most criteria pollutants because fuel gas with hydrogen is a much cleaner fuel and results in less CO_2.

OxyChem will use hydrogen-rich fuel gas as a preferred fuel for the furnaces and will minimize CO_2 emissions in this way. The only exception to burning this fuel gas is that some of the produced hydrogen will be used in the facilities' hydrogenation processes.

The emission calculations in Appendix C indicate that firing natural gas results in worst-case CO_2 emissions and firing high-hydrogen fuel gas results in worst-case CH_4 and N_2O emissions.

EPN's CR-1-MSS through CR-5-MSS; Ethane Cracking Furnaces Nos. 1 through 5 - MSS Activities

The ethane cracking furnaces mentioned above have three additional scenarios that can be described as follows:

1) Furnace Cold Start-up - When the furnaces are starting up after a complete plant shutdown, there is no process generated fuel gas available and pipeline supplied natural gas is fired in the furnaces.

2) Hot Steam Standby - Hot steam standby mode of operation is established immediately after a furnace has completed a steam decoke. During hot steam standby, the furnace has steam flowing through the tubes, minimum firing rate on the firebox, and the furnace discharge is routed to the quench tower. This operation mode is maintained until the furnace is placed back in the normal operation mode.

3) Steam Decoking - Due to the high furnace tube temperatures during normal operations, coke deposits build up on the furnace tube walls. To maintain efficient furnace operation, this coke must be removed periodically using a steam decoking process.

   The steam decoking process is started by cutting the ethane feed to an operating furnace while leaving steam flowing through the furnace tubes, and maintaining fire box heat input at a reduced rate. The furnace discharge continues to feed forward to the quench tower until the ethane is purged from the furnace tubes.

   Once the furnace tubes are cleared of ethane, the furnace discharge is diverted from the quench tower to the furnace fire box. Air is added to the furnace tubes along with steam, to begin burning coke in the furnace tubes.

   The air flow is gradually increased until all of the coke is burned off. Once decoking has been completed, the air flow to the tubes is cut off, steam flow is maintained on the furnace tubes, minimum firing is maintained on the fire box and the furnace outlet is re-routed to the quench column.

The emissions from these activities were reviewed and the only possible increase in GHG emissions involves the steam decoking scenario. However, as shown in the Appendix C calculations, steam decoking GHG emissions are not greater than emissions estimated for normal operations.

EPN's CR-6 and CR-7; CR Thermal Oxidizer Nos. 1 and 2

The thermal oxidizer system for the proposed facilities includes two identical combustion units expected to fire fuel gas and waste gas at a maximum rate of 85 MM Btu/hr. Typically, these units will both be operating and will share the load of waste gases generated by the new facilities.

Waste gases include both continuous and intermittent streams from the process and storage vessels. All non-pressurized storage tanks at the site handling VOC materials with vapor pressures greater than 0.5 psia are vented to the thermal oxidizers for control.

Also, pyrolysis gasoline truck loading will be handled through the oxidizers. The pressure ratings of trucks are sufficient to maintain 100% collection of displaced vapors.

Since each thermal oxidizer is capable of handling all of the waste gas from the proposed facilities, each unit will be permitted at maximum rates so that operational flexibility is maximized. Also, the thermal oxidizers will be equipped with heat recovery boilers for increased energy efficiency. Steam generation from these units is intended to reduce the demand for steam from the existing cogeneration units.

EPN CR-8; CR High Pressure Flare

The high pressure ground flare is included in the emission calculations because its pilots burn natural gas. Otherwise, all gases routed to the flare will be the result of MSS events (see EPN CR-8-MSS) or upsets (emission events). Since emission events are not subject to permitting requirements, they are not addressed in this application.

EPN CR-8-MSS; CR High Pressure Flare - MSS Activities

The high pressure ground flare's start-up and shutdown emissions are included in this authorization. It should be noted that the number of events, gas input mass rates and hours per event represented in the Appendix C calculations are provided for calculation purposes only; these parameters could change, but the annual emission rates will not be exceeded.

EPN's CR-9; CR Emergency Generator Diesel Engine

The diesel-fired emergency generator engine is included in the emission calculations because of emissions that occur during the scheduled testing of this engine. The use of this engine for emergency conditions will not be authorized by this permit since these events are not subject to permitting requirements.

EPN CR-10; CR Low Pressure Flare

The low pressure, enclosed flare is included in the emission calculations because its pilots burn natural gas. Otherwise, most all of the gases routed to the flare will be the result of upsets (emission events), which are events that are not subject to permitting requirements. MSS activities for this flare are addressed under EPN CR-10-MSS.

EPN CR-10-MSS; CR Low Pressure Flare - MSS Activities

The low pressure flare could be used for the rare circumstance when both of the thermal oxidizers may be out of service. Therefore, additional CO_2e is estimated for the flare to reflect 2% of a single thermal oxidizer's emissions for the rare occurrence that both thermal oxidizers are down. When both thermal oxidizers are down, the flare will handle all waste gas.

EPN CR-11; CR Cooling Tower

The make-up water for the cooling tower is treated surface water from the local municipal water district and this water contains naturally occurring dissolved minerals and bicarbonate ions that will tend to concentrate in the cooling tower water, raising the pH and alkalinity. To prevent scale formation, acid is injected into the circulation water system to reduce the alkalinity and pH.

In the process, bicarbonate ion is converted into CO_2 which de-gasses in the cooling tower. CO_2 is discharged to the atmosphere through the mechanical draft cooling tower fan stacks.

The CO_2 emissions are conservatively estimated using the maximum expected bicarbonate concentration and cooling tower make-up water flow rate assuming all the bicarbonate ion is converted to CO_2. In actual practice some bicarbonate remains in the circulating water and is removed with the blowdown water from the cooling tower.

EPN CR-12; C3/C4 Hydrogenation Regeneration Vent – MSS Activities

Hydrogenation reactors will be used to convert olefinic C3 and C4 compounds to saturated compounds. Periodic regeneration of these reactors is required to remove coke and residual hydrocarbon deposits from the catalyst. This regeneration process is started by shutting off the process flow to the reactor and routing the reactor discharge to the quench tower.

Steam is used to sweep hydrocarbons from the reactor into the quench column for recovery of these materials. After the steam sweep is completed, the reactor discharge is routed to an atmospheric vent. High pressure steam and air are used to burn the remaining coke and residual hydrocarbons from the reactor catalyst.

EPN's CR-13, 14, 17 and 16; Ethylene Plant Fugitive Emissions

Fugitive emissions were estimated for the state PSD application for six areas of the proposed facilities: the CR Furnace Area Fugitives (EPN CR-13), the CR Charge Gas Area Fugitives (EPN CR-14), the CR Recovery Area Fugitives (EPN CR-15), the CR C3+ Area Fugitives (EPN CR-16), the CR Waste Treatment and C5 Area Fugitives (EPN CR-17) and the CR LPG Storage Area Fugitives (EPN CR-18). However, since the last two areas do not contain GHG pollutants, they are not included in this GHG application. Calculations utilize the TCEQ's SOCMI factors with ethylene, without ethylene and average factors, all based on the ethylene content of the streams.

Fugitive emissions are minimized with the use of a TCEQ-styled 28MID fugitive monitoring and maintenance program with quarterly monitoring of flanges. This program with quarterly monitoring of flanges is a more aggressive program that the TCEQ-styled 28LAER program. New pumps and compressors in VOC service will have dual mechanical seals that route vapor losses to the thermal oxidizer or will be of equivalent non-leaker design.

Relief valves that vent to control devices and relief valves that are equipped with rupture discs and pressure indicators are not identified in the calculations since their control is expected to be 100%. Relief valves associated with contaminated water storage and gasoline storage cannot be equipped with rupture discs since they operate at low pressure. It should be noted that these tanks are initially routed to the thermal oxidizers for control, so losses through the relief valves are a secondary option for managing these tank losses.

VOC speciation is provided with the fugitive emission calculations and these VOC representations are the best available at this time and could vary slightly. This speciation includes a reasonable VOC distribution for the materials expected to be processed at the site.

Summary calculations are only provided for four of the six fugitives areas within the Ethylene Plant since these areas are the only ones that include GHG emissions. These areas include the following: the CR Furnace Area Fugitives (EPN CR-13), the CR Charge Gas Area Fugitives (EPN CR-14), the CR Recovery Area Fugitives (EPN CR-15) and the CR C3+ Area Fugitives (EPN CR-16).

Detailed calculations can be provided for each of about 40 distinct portions of the six fugitive areas (those with unique VOC speciation), but due to the volume of the calculations and the relatively small GHG quantities involved, these details are not included in this application. Nevertheless, one example calculation is provided in Appendix C that details the calculations for the binary refrigeration area within the CR Recovery Area Fugitives, EPN CR-15.

VOC and GHG speciation is provided with the fugitive emission calculations. This speciation includes a reasonable GHG distribution for the Ethylene Plant based on materials expected to be processed at the site. Fugitive methane emissions are about 3 tons/yr and CO_2 emissions are less than 0.1 ton/yr.

EPN's CG-1 and CG-2; Existing Cogeneration Units

As mentioned previously, the existing cogeneration units are not being modified and their increased fuel firing will not exceed previously authorized levels. However, as affected sources the cogenerations units will enter in the scope of the project to supply the new demand for steam and power for the proposed facilities.

Therefore, for the purpose of the current PSD permit review, the emissions from the increase in fuel firing expected from these existing units will need to be added to the emissions associated with the proposed new facilities. In this regard, it has been determined that a maximum 215 MM Btu/hr increase in fuel firing is needed when steam and power are provided by the cogeneration units' heat recovery steam boilers for the new Ethylene Plant.

It is likely that the increase in steam and power will occur from increased firing of the gas turbines, but since the higher efficiency turbines' emissions do not represent worst-case, the steam boilers were chosen for the purpose of estimating emission increases. Also, it should be noted that since the two cogeneration facilities are identical, the increased fuel firing could occur from either unit with no difference in the calculated emissions.

Proposed GHG Emissions

A summary of maximum GHG emissions to be authorized for the proposed Ethylene Plant is provided on the following page.

EPN	Sources	Annual CO_2e Emissions (tons/yr)			
		CO_2-related CO_2e	CH_4-related CO_2e	N_2O-related CO_2e	Total CO_2e
CR-1	Ethane Cracking Furnace No. 1	140,817.01	167.43	494.31	141,478.75
CR-2	Ethane Cracking Furnace No. 2	140,817.01	167.43	494.31	141,478.75
CR-3	Ethane Cracking Furnace No. 3	140,817.01	167.43	494.31	141,478.75
CR-4	Ethane Cracking Furnace No. 4	140,817.01	167.43	494.31	141,478.75
CR-5	Ethane Cracking Furnace No. 5	140,817.01	167.43	494.31	141,478.75
CR-6	CR Thermal Oxidizer No. 1	53,938.77	48.49	140.76	54,128.02
CR-7	CR Thermal Oxidizer No. 2	53,938.77	48.49	140.76	54,128.02
CR-8	CR High Pressure Flare	842.24	0.33	0.49	843.07
CR-8-MSS	CR High Pressure Flare - MSS	69,541.37	76.65	226.29	69,844.31
CR-9	CR Emergency Generator Diesel Engine	61.44	0.05	0.15	61.65
CR-10	CR Low Pressure Flare	168.45	0.07	0.10	168.61
CR-10-MSS	CR Low Pressure Flare - MSS	1,078.78	0.97	2.82	1,082.56
CR-11	CR Cooling Tower	802.09	0.00	0.00	802.09
CR-12-MSS	C3/C4 Hydro. Regen. Vent - MSS	12.93	0.03	0.06	13.02
CR-13	CR Furnace Area Fugitives	0.01	28.39	0.00	28.40
CR-14	CR Charge Gas Area Fugitives	0.00	8.78	0.00	8.79
CR-15	CR Recovery Area Fugitives	0.00	23.59	0.00	23.59
CR-16	CR C3+ Area Fugitives	0.00	5.42	0.00	5.42
CG-1/CG-2	Cogeneration Units	110,093.30	43.61	64.37	110,201.27
Totals		994,563.21	1,121.99	3,047.34	998,732.54

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REGULATORY REQUIREMENTS

OxyChem's new Ethylene Plant will comply with all applicable PSD regulatory requirements. Details of these permitting requirements and the company's compliance are explained below for the requirements found in 40 CFR 52.21(j)-(w).

(j) Control technology review.

One aspect of the required control technology review is that a major stationary source or major modification must comply with each applicable emissions limitation under the State Implementation Plan and each applicable emission standard and standard of performance under 40 CFR parts 60 and 61. However, since GHG emissions are not addressed in these requirements, the proposed facilities are not subject to any of these standards.

Also, new major stationary sources and major modifications must apply best available control technology for each regulated NSR pollutant subject to PSD review. The review of BACT using the EPA's five-step, top-down BACT approach typically includes the following items for each source category: 1) the identification of available control technologies; 2) the elimination of the technically infeasible alternatives; 3) the ranking of the remaining control technologies; 4) the evaluation of the most effective controls regarding cost-effectiveness, energy impacts, and environmental effects; and 5) the selection of BACT.

For the sources associated with the proposed facilities, this BACT review is provided in Appendix D, Best Available Control Technology. It should be noted that the existing cogeneration units are not subject to BACT since they are not modified sources. The cogeneration units are included in this application because they are considered affected facilities that influence PSD applicability.

(k) Source impact analysis.

Subsection (k) requirements prevent a proposed source or modification from causing or contributing to a violation of a national ambient air quality standard (NAAQS) or an applicable maximum allowable increase over the baseline concentration in any area. However, since NAAQS and baseline concentrations have not been established for GHGs, these requirements are not relevant to this application.

(l) Air quality models.

Subsection (l) requirements specify that all estimates of ambient concentrations must be based on applicable air quality models, data bases, and other requirements specified in Appendix W of 40 CFR 51 (Guideline on Air Quality Models). However, since no air quality modeling is required for GHGs, these specifications are not applicable.

(m) Air quality analysis.

The air quality requirements for pre-application monitoring and post-construction monitoring in Subsection (m) of the rules is not required for GHGs since EPA regulations provide an exemption in 40 CFR 52.21(i)(5)(iii) and 51.166(i)(5)(iii) for pollutants, including GHGs, that are not listed in the appropriate section of the regulations. Therefore, it is understood that the EPA does not require applicants to gather monitoring data to evaluate ambient air quality for GHGs under 40 CFR 52.21(m)(1)(ii), 40 CFR 51.166(m)(1)(ii) or similar provisions.

(n) Source information.

The GHG permit applicant is required to provide all information necessary to perform any analysis or make any determination required under these PSD rules, including the following: a description of the nature, location, design capacity and typical operating schedule of the source, a schedule for construction of the source, a detailed description of emission controls, emission estimates and any other information necessary relative to demonstrating BACT. This information is provided in the previous process discussion and in Appendices A, B, C and D.

Also, it is understood that upon request of the Administrator, the applicant must provide information on the air quality impact of the new sources, including meteorological and topographical data necessary to estimate such impact, and the nature and extent of any or all general commercial, residential, industrial, and other growth expected to occur as a result of the proposed project.

In addition, it is understood that EPA is required to ensure compliance with the Endangered Species Act, the National Historic Preservation Act, Environmental Justice mandates, and the Magnuson-Stevens Fishery Conservation and Management Act, as applicable to agency decisions regarding the GHG PSD permit issuance process.

Endangered Species Act (ESA):

It is our understanding that OxyChem will serve as its non-federal agent for informal consultation and the associated compliance review process pursuant to ESA. The U.S. Fish and Wildlife Service (USFWS) office of jurisdiction will likely be the Corpus Christi Field Office.

The initial informal consultation process typically includes identifying the list of federally-listed threatened and endangered (T&E) species that may occur in each county within the action area, collecting existing baseline information on each species (e.g., habitat requirements, approved survey protocols, known records of occurrence, etc.), performing potential habitat surveys of the action area, and identifying potential occurrences and associated project impacts on each species.

If no T&E species are listed within the action area, then the USFWS typically would concur with a "no effect" determination. If no known occurrences or potential habitat for identified T&E species are present within the action area, then the USFWS typically would concur with a "not likely to adversely affect" determination. Either of these determinations would conclude the informal consultation process, and obviate the need to enter into formal consultation.

The formal consultation process is reserved for projects that are likely to adversely affect a federally-listed T&E species. Under this process, the EPA would request that OxyChem conduct any required in-field, habitat and species-specific surveys, prepare a Biological Assessment (BA) on behalf of EPA, and file the BA with USFWS. If upon BA review the USFWS determines the project is not likely to adversely affect a T&E species, the formal consultation is then concluded.

OxyChem's documentation in satisfaction of these requirements is separate from the current GHG PSD permit application submittal. Nevertheless, the appropriate reports will be provided to the EPA as they become available in the near term.

National Historic Preservation Act (NHPA):

For the proposed Ethylene Plant, an approval letter from the executive director of the Texas Historical Commission (THC) will likely meet the EPA's NHPA compliance requirements. The EPA will retain primary consultation authority for NHPA compliance, and will not request that OxyChem serve as its non-federal agent. If additional analysis is required by the THC prior to approval, OxyChem will need to perform the cultural resource research, field work, and reports for submittal to THC, but the EPA will be provided the opportunity to review the reports prior to transmittal to the THC.

Environmental Justice (EJ):

OxyChem's understanding is that the EPA will be responsible for evaluating whether operation of the proposed ethylene production facilities will result in an EJ concern. The EPA is expected to run a model to perform the EJ evaluation. The EPA does not anticipate that OxyChem will need to perform any additional evaluations.

Magnuson-Stevens Fishery Conservation and Management Act (MSFCMA):

For the proposed Ethylene Plant, an approval letter from the National Oceanic and Atmospheric Administration-National Marine Fisheries Service (NOAA-NMFS), Habitat Conservation Division, Galveston Office will likely meet the EPA's MSFCMA compliance requirements. It is our understanding that the EPA will retain primary consultation authority for MSFCMA compliance and will not request that OxyChem serve as its non-federal agent.

If additional analysis is required by the NMFS-Habitat Conservation Division prior to approval, OxyChem will prepare an Essential Fish Habitat (EFH) Assessment for submittal to NMFS-Habitat Conservation Division and the EPA will be provided the opportunity to review the report prior to transmittal to the NMFS-Habitat Conservation Division.

(o) Additional impact analyses.

Subsection (o) requirements typically result in an analysis of the potential impairment to visibility, soils and vegetation that may occur as a result of the proposed source or modification and the expected general commercial, residential, industrial and other growth. Also, the Administrator may require monitoring of visibility in any nearby Federal Class I area.

However, an impact analysis is not required for GHG pollutants. The EPA's document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" prepared by the Office of Air Quality Planning and Standards and dated March 2011, states the EPA's belief that it is not necessary for applicants to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for several reasons. The reasons provided by the EPA are that climate change modeling and impact evaluations are typically conducted for changes in emissions much larger than those from individual projects and that quantifying the impacts from a specific, permitted GHG source would not be possible with current climate change models.

This EPA document concludes that the most practical approach to addressing Class I areas and additional impacts analysis is to focus on maximizing the reduction of GHGs through compliance with the BACT analysis.

(p) Sources impacting Federal Class I areas - additional requirements.

Subsection (p) rules include the requirement that the Administrator provide written notice of the permit application and provide other information for a proposed major stationary source or major modification when the emissions may affect a Federal Class I area. Since the nearest Class I area is the Big Bend National Park, which is located more than 350 miles (600 kilometers) from the proposed facilities, the emissions from this project are not expected to have an impact on this Class I area. In addition, the EPA position explained in Item (o) regarding additional impact analyses appears to apply to these additional Class I concerns.

(q) Public participation.

Subsection (q) rules place certain requirements on the Administrator to follow the applicable public notice procedures of 40 CFR 124 in processing applications under this section. It is expected that the Administrator will follow the procedures at 40 CFR 52.21(r) to the extent that the procedures of 40 CFR 124 do not apply.

(r) Source obligation.

It is understood that these requirements preclude an owner or operator from constructing or operating a source or modification not in accordance with the application submitted pursuant to these PSD requirements or with the terms of the issued permit. In addition, it is understood that the permit is invalid if construction is not commenced within 18 months after receipt of the permit (unless an extension is authorized), if construction is discontinued for a period of 18 months or more, and if construction is not completed within a reasonable time.

(s) Environmental impact statements.

These rules state that whenever a proposed source is subject to permitting action by a federal agency that might necessitate preparation of an environmental impact statement pursuant to the National Environmental Policy Act (NEPA, 42 U.S.C. 4321), review by the Administrator conducted pursuant to this section shall be coordinated with the environmental reviews under that Act and under Section 309 of the Clean Air Act. However, it appears that NEPA is not applicable to this GHG permit action because of the exemption from NEPA for air permitting (15 USC § 793(c)).

(t) Disputed permits or redesignations.

OxyChem understands that certain affected parties who determine a proposed permit will cause or contribute to a cumulative change in air quality in excess of that allowed by these rules may request the Administrator to enter into negotiations with the parties involved to resolve the concerns.

(u) Delegation of authority.

OxyChem understands that the delegation of responsibility for conducting GHG source review permitting has not occurred in Texas, and therefore, this application is being submitted to the Region 6 Office of the EPA.

(v) Innovative control technology.

OxyChem understands that certain regulatory options exist for implementing innovative control technology for a PSD permit. However, no innovative controls are proposed for the new ethylene production facilities.

(w) Permit rescission.

OxyChem understands that a permit issued under these PSD rules shall remain in effect, unless and until it expires under the regulations referenced above or is rescinded.

APPENDIX A
GENERAL APPLICATION AND PSD APPLICABILITY FORMS

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

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

I. Applicant Information		
A. Company or Other Legal Name: Occidental Chemical Corporation		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: Paul A. Thomas		
Title: Plant Manager		
Mailing Address: P.O. Box CC		
City: Ingleside	State: TX	ZIP Code: 78362-0720
Telephone No.: (361) 776-6169	Fax No.: (361) 776-6240	E-mail Address: Mark_Evans@oxy.com
C. Technical Contact Name: Mark R. Evans		
Title: Environmental Manager		
Company Name: Occidental Chemical Corporation		
Mailing Address: P.O. Box CC		
City: Ingleside	State: TX	ZIP Code: 78362-0720
Telephone No.: (361) 776-6169	Fax No.: (361) 776-6240	E-mail Address: Mark_Evans@oxy.com
D. Site Name: Ingleside Chemical Plant		
E. Area Name/Type of Facility: Ethylene Plant		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Chemical Manufacturing		
Principal Standard Industrial Classification Code (SIC): 2869		
Principal North American Industry Classification System (NAICS): 325199		
G. Projected Start of Construction Date: 12/1/2014		
Projected Start of Operation Date: 2/1/2017		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 4133 Hwy 361; 2 miles west of Hwy 1069 on Hwy 361		
City/Town: Gregory	County: San Patricio	ZIP Code: 78359
Latitude (nearest second): 27° 52' 51"	Longitude (nearest second): 97° 14' 39"	

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

TCEQ

I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility): SD-0092-F	
J. Core Data Form.	
Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L).	☐ YES ☒ NO
K. Customer Reference Number (CN): 600125256	
L. Regulated Entity Number (RN): 100211176	
II. General Information	
A. Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.	☐ YES ☒ NO
B. Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES ☒ NO
C. Number of New Jobs: 123	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: Judith Zarrafini	District No.: 21
State Representative: Todd Hunter	District No.: 32
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested. ☒ Initial ☐ Amendment ☐ Revision (30 TAC 116.116(e) ☐ Change of Location ☐ Relocation	
B. Permit Number (if existing):	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* ☒ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit ☒ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source ☐ Other:	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

III. Type of Permit Action Requested *(continued)*	
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.0	☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):	
Street Address:	
City: County: ZIP Code:	
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):	
Street Address:	
City: County: ZIP Code:	
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO", attach detailed information.	☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?	☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.	
List: none	
G. Are you permitting planned maintenance, startup, and shutdown emissions? If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.	☒ YES ☐ NO
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) Is this facility located at a site required to obtain a federal operating permit? If Yes, list all associated permit number(s), attach pages as needed).	☒ YES ☐ NO ☐ To be determined
Associated Permit No (s.): O1240 for the existing site; a new permit will be requested for the proposed facilities	
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this 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	

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

III.	**Type of Permit Action Requested *(continued)***	
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
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	
IV.	**Public Notice Applicability**	
A.	Is this a new permit application or a change of location application?	☒ YES ☐ NO
B.	Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C.	Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☒ YES ☐ NO
D.	Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES ☒ NO
If Yes, list the affected state(s) and/or Class I Area(s).		
List:		
E.	Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.	☐ YES ☒ NO
1.	Is there any change in character of emissions in this application?	☐ YES ☐ NO
2.	Is there a new air contaminant in this application?	☐ YES ☐ NO
3.	Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
F.	List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***	
Greenhouse Gases (GHG): 998,732.54 tons/yr		
Volatile Organic Compounds (VOC):		
Sulfur Dioxide (SO2):		
Carbon Monoxide (CO):		
Nitrogen Oxides (NOx):		
Particulate Matter (PM):		
PM 10 microns or less (PM10):		
PM 2.5 microns or less (PM2.5):		
Hazardous Air Pollutants (HAPs):		
Other speciated air contaminants not listed above:		

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

V. Public Notice Information ***(complete if applicable)***			
A. Public Notice Contact Name: Mark R. Evans			
Title: Environmental Manager			
Mailing Address: P.O.Box CC			
City: Ingleside	State: TX	ZIP Code: 78362-0720	
B. Name of the Public Place: Bell Whittington Public Library			
Physical Address *(No P.O. Boxes)*: 2400 Memorial Parkway			
City: Portland	County: San Patricio	ZIP Code: 78374	
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
C. Concrete Batch Plants, PSD, and Nonattainment Permits			
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.			
The Honorable: Judge Terry A. Simpson			
Mailing Address: 400 West Sinton Street #109			
City: Sinton	State: TX	ZIP Code: 78387	
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***			☐ YES ☐ NO
Presiding Officers Name(s):			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located.			
Chief Executive: Mayor Freddy Garcia			
Mailing Address: 204 W 4th Street			
City: Gregory	State: TX	ZIP Code: 78359	
Name of the Indian Governing Body: N/A			
Mailing Address:			
City:	State:	ZIP Code:	

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

V.	**Public Notice Information *(complete if applicable) (continued)***	
C.	Concrete Batch Plants, PSD, and Nonattainment Permits	
3.	Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. *(continued)*	
Name of the Federal Land Manager(s):		
D.	Bilingual Notice	
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, list which languages are required by the bilingual program?		
VI.	**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 stationary source for federal air quality permitting?	☒ YES ☐ NO
C.	Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☒ YES ☐ NO
D.	Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☐ YES ☒ NO
VII.	**Technical Information**	
A.	The following information must be submitted with your Form PI-1 ***(this is just a checklist to make sure you have included everything)***	
1.	☒ Current Area Map	
2.	☒ Plot Plan	
3.	☒ Existing Authorizations	
4.	☒ Process Flow Diagram	
5.	☒ Process Description	
6.	☒ Maximum Emissions Data and Calculations	
7.	☒ Air Permit Application Tables	
a.	☒ Table 1(a) (Form 10153) entitled, Emission Point Summary	
b.	☒ Table 2 (Form 10155) entitled, Material Balance	
c.	☒ Other equipment, process or control device tables	
B.	Are any schools located within 3,000 feet of this facility?	☐ YES ☒ NO

VII.	**Technical Information**			
C.	Maximum Operating Schedule:			
Hour(s): 24	Day(s): 7	Week(s): 52	Year(s):	
Seasonal Operation? If Yes, please describe in the space provide below.				☐ YES ☒ NO
D.	Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.				
E.	Does this application involve any air contaminants for which a disaster review is required?			☒ YES ☐ NO
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?			☐ YES ☒ NO
VIII.	**State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*			
A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?			☒ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?			☒ YES ☐ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?			☒ YES ☐ NO
D.	Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?			☒ YES ☐ NO
IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*			
A.	Does 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

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
Is the estimated capital cost of the project greater than $2 million dollars?		☒ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.		
XI.	**Permit Fee Information**	
Check, Money Order, Transaction Number ,ePay Voucher Number:		Fee Amount:
Paid online?		☐ YES ☐ NO
Company name on check:		
Is a copy of the check or money order attached to the original submittal of this application?		☐ YES ☐ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?		☐ YES ☐ NO ☐ N/A

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

XII. Delinquent Fees and Penalties
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.texas.gov/agency/delin/index.html.
XIII. 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. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: Paul A. Thomas
Signature: Paul A. Thomas *Original Signature Required*
Date: 12/17/12

TCEQ

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: To be assigned	Application Submittal Date: December 2012
Company: Occidental Chemical Corporation	
RN: 100211176	Facility Location: 4133 Hwy 361
City: Gregory	County: San Patricio
Permit Unit I.D.: Ethylene Plant	Permit Name: Ethylene Plant
Permit Activity: ☒ New Source ☐ Modification	
Project or Process Description: Cracking of ethane to produce ethylene	

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS								
	Ozone		CO	PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	Other[1]
	VOC	NO_X							
Nonattainment? (yes or no)	no	no	no	no	no	no	no	no	no
Existing site PTE (tpy)?	na	na	na	na	na	na	na	na	>100,000
Proposed project emission increases (tpy from Table 2F)[3]	na	na	na	na	na	na	na	na	998,733
Is the existing site a major source? (yes or no) [2]If not, is the project a major source by itself?	na	na	na	na	na	na	na	na	yes
If site is major, is project increase significant?	na	na	na	na	na	na	na	na	yes
If netting required, estimated start of construction?		12/1/14							
Five years prior to start of construction		12/1/09					contemporaneous		
Estimated start of operation		2/1/17						period	
Net contemporaneous change, including proposed project, from Table 3F. (tpy)	na	na	na	na	na	na	na	na	1,242,100
FNSR APPLICABLE? (yes or no)	na	na	na	na	na	na	na	na	yes

1 Other PSD pollutants. Greenhouse gases (GHGs)
2 Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR § 51.166(b)(1).
3 Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR § 51.166(b)(23).

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

Paul A. Monroe	Plant Manager	12/20/12
Signature	Title	Date

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant: GHG	Permit: To be assigned
Baseline Period: 1/1/10 to 12/31/11	

	Affected or Modified Facilities FIN	EPN	Permit No.	Actual Emissions	A Baseline Emissions	B Proposed Emissions	Projected Actual Emissions	Difference (A-B)	Correction	Project Increase
1	CR-1	CR-1	tba	0.00	0.00	141,478.75		141,478.75		141,478.75
2	CR-2	CR-2	tba	0.00	0.00	141,478.75		141,478.75		141,478.75
3	CR-3	CR-3	tba	0.00	0.00	141,478.75		141,478.75		141,478.75
4	CR-4	CR-4	tba	0.00	0.00	141,478.75		141,478.75		141,478.75
5	CR-5	CR-5	tba	0.00	0.00	141,478.75		141,478.75		141,478.75
6	CR-5-MSS	CR-10	tba	0.00	0.00	0.00		0.00		0.00
7	CR-6	CR-11	tba	0.00	0.00	54,128.02		54,128.02		54,128.02
8	CR-7	CR-12	tba	0.00	0.00	54,128.02		54,128.02		54,128.02
9	CR-8	CR-13	tba	0.00	0.00	843.07		843.07		843.07
10	CR-8-MSS	CR-14	tba	0.00	0.00	69,844.31		69,844.31		69,844.31
11	CR-9	CR-9	tba	0.00	0.00	61.65		61.65		61.65
12	CR-10	CR-10	tba	0.00	0.00	168.61		168.61		168.61
13	CR-10-MSS	CR-10-MSS	tba	0.00	0.00	1,082.56		1,082.56		1,082.56
14	CR-11	CR-11	tba	0.00	0.00	34,780.59		34,780.59		802.09
								Page Subtotal		888,452.05*

* The page subtotal corrects for some rounding elements of the application's EXCEL spreadsheet calculations for these sources.

TCEQ

TABLE 2F (cont'd)
PROJECT EMISSION INCREASE

Pollutant: GHG	**Permit:** To be assigned
Baseline Period: 1/1/10 to 12/31/11	

	Affected or Modified Facilities FIN	EPN	Permit No.	Actual Emissions	A Baseline Emissions	B Proposed Emissions	Projected Actual Emissions	Difference (A-B)	Correction	Project Increase
15	CR-12	CR-12	tba	0.00	0.00	13.02		13.02		13.02
16	CR-13	CG-13	tba	0.00	0.00	28.40		28.40		28.40
17	CR-14	CR-14	tba	0.00	0.00	8.79		8.79		8.79
18	CR-15	CR-15	tba	0.00	0.00	23.59		23.59		23.59
19	CR-16	CR-16	tba	0.00	0.00	5.42		5.42		5.42
20	CG-1/CG-2	CG-1/CG-2	tba	0.00*	0.00*	110,201.27		110,201.27		110,201.27
21										
22										
23										
24										
25										
26										
27							**Page Subtotal**			110,280.49
28							**Previous Page Subtotal**			888,452.05
							GHG Total			998,732.54

* Baseline emissions are not needed for sources that are not modified. These cogeneration units are affected sources that will provide steam and power to the new Ethylene Plant, but they are not modified. Their increased criteria pollutant emission rates will not exceed permit limits that were previously authorized under Permit Nos. 35335 and PSD-TX-880.

TCEQ

TABLE 3F
PROJECT CONTEMPORANEOUS CHANGES

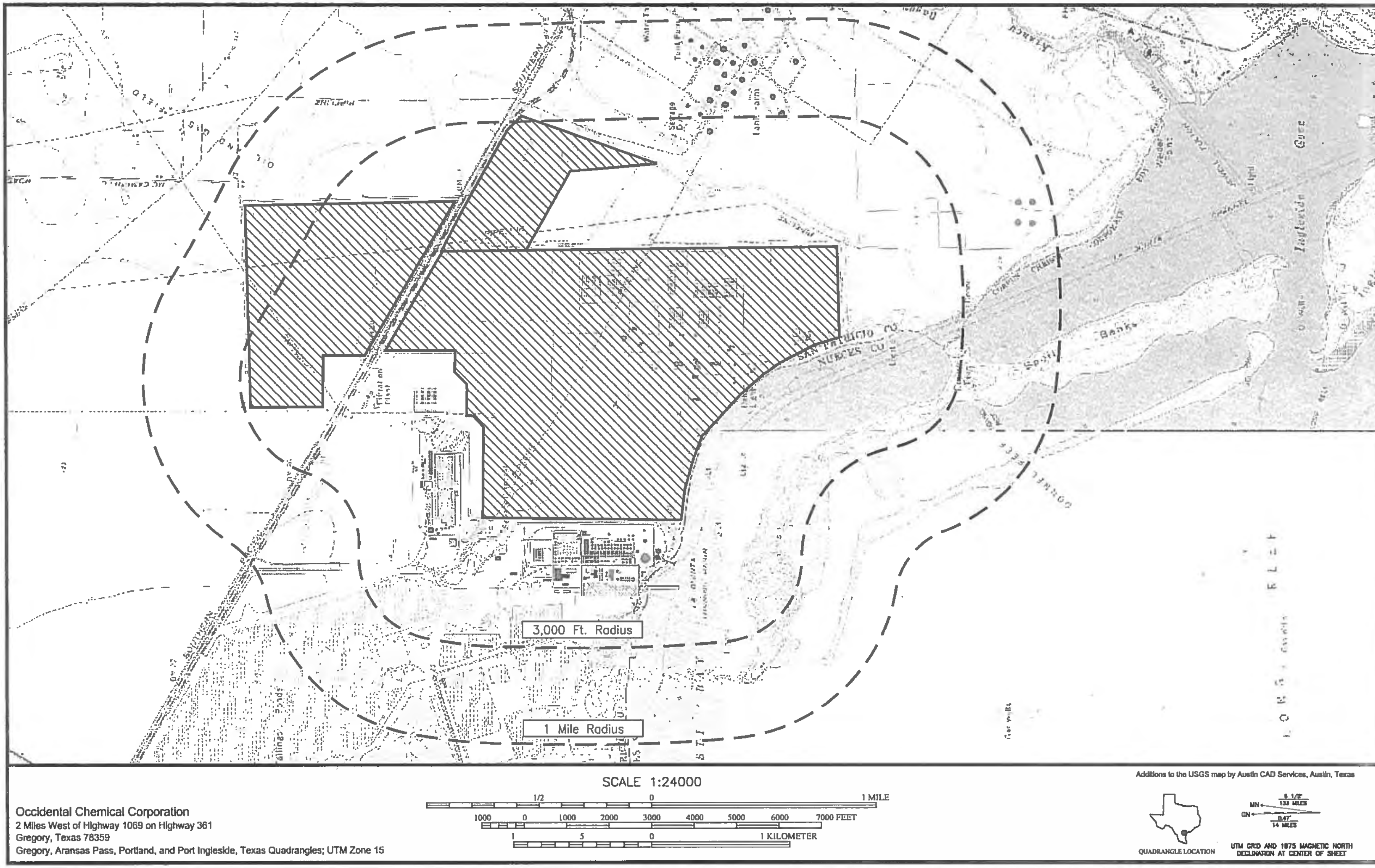
Company: Occidental Chemical Corporation	
Permit Application Number: To be assigned	**Criteria Pollutant:** GHG

	Project Date	Facility at Which Emission Change Occurred FIN	EPN	Permit No.	Project Name or Activity	A Baseline Period	B Baseline Emissions (tons/year)	Proposed Emissions (tons/year)	Difference (A-B)	Creditable Decrease or Increase
1	2/2017	CR-1 thru CR16; CG-1 and CG-2	CR-1 thru CR16; CG-1 and CG-2	To be assigned	Ethylene Plant	1/10-12/11	0.00	998,732.54	998,732.54	998,732.54
2	7/2014	NGL-1 thru 14; CG-1 and CG-2	NGL-1 thru 14; CG-1 and CG-2	PSD-TX-1292-GHG	NGL Fractionation Facilities	1/10-12/11	0.00	243,367.87*	243,367.87	243,367.87
3										
4										
5										
6										
7										
8										
9										
10										
11										
						Page Subtotal				1,242,100.41
									Project Emission	1,242,100.41
Summary of Contemporaneous Changes							**Total**			1,242,100.41

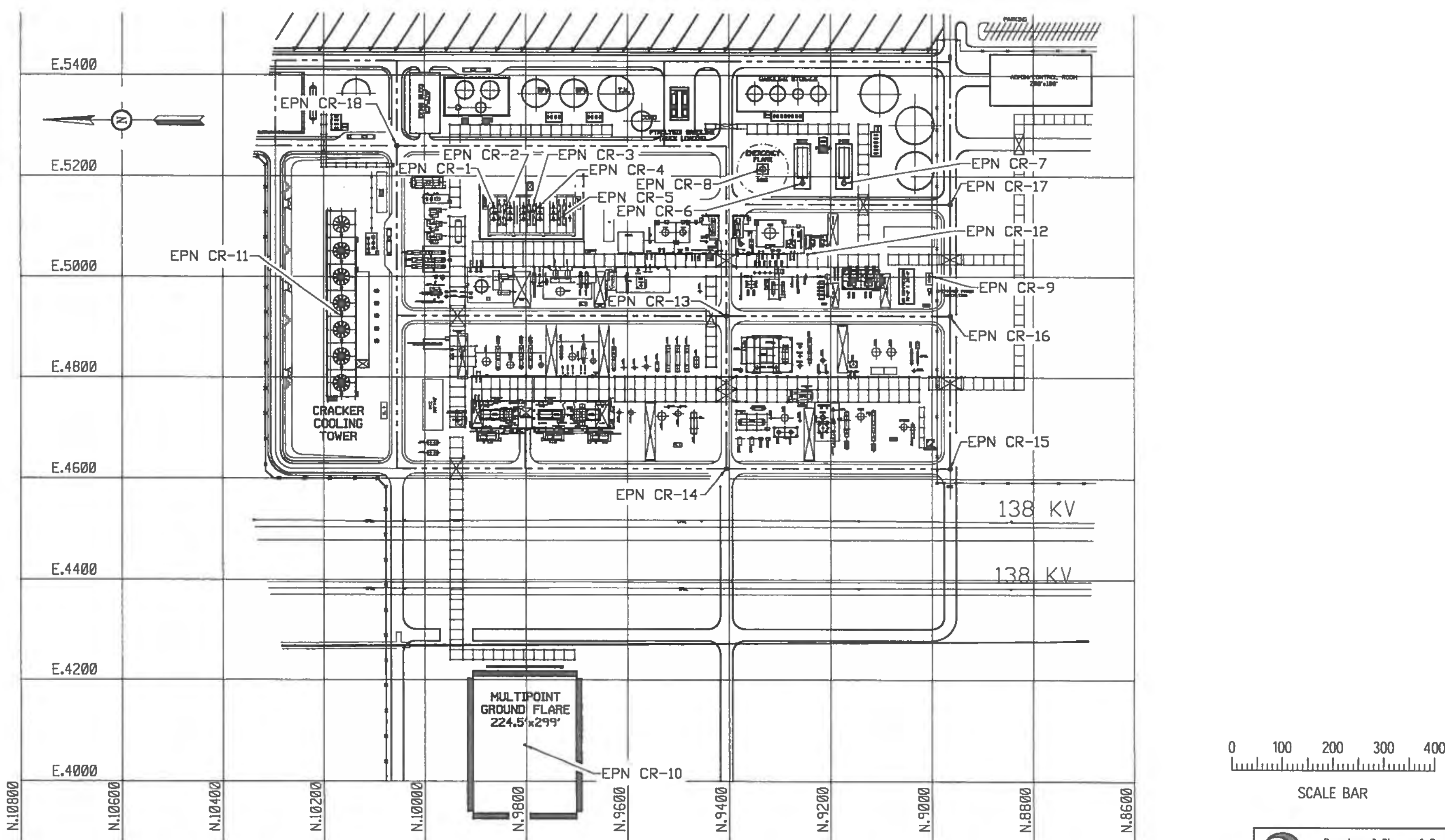
* The 243,367.87 tons/yr increase is the sum of 242,536.30 tons/yr, indicated in the initial application, and 831.57 tons/yr, indicated in the deficiency response dated August 1, 2012.

Occidental Chemical Corporation
December 2012

APPENDIX B
AREA MAP, PLOT PLAN AND OTHER SUPPORTING DOCUMENTS



Occidental Chemical Corporation
2 Miles West of Highway 1069 on Highway 361
Gregory, Texas 78359
Gregory, Aransas Pass, Portland, and Port Ingleside, Texas Quadrangles; UTM Zone 15



Occidental Chemical Corporation
A subsidiary of Occidental Petroleum Corporation

INGLESIDE ETHYLENE PLANT
EMISSION POINTS SOURCES

NO.	REVISION	DRAWN	CK'D	APPD	DATE
-	-	-	-	-	-
-	-	-	-	-	-
D	ISSUED FOR CLIENT REVIEW	RR	DG	RWM	17-DEC-12
C	ISSUED FOR CLIENT REVIEW	RR	DG	RWM	10-DEC-12
B	ISSUED FOR CLIENT REVIEW	RR	DG	RWM	30-NOV-12
A	ISSUED FOR CLIENT REVIEW	RR	DG	RWM	16-NOV-12

NOTES

REFERENCE DRAWINGS

DRAWN: RR | CK'D: DG | APPD: RWM | DATE: 13NOV12 | SCALE: SEE BAR SCALE

FOR: Occidental Chemical Corporation

PROJECT NO. 181872 | DWG NO. 181872-000-HS-08-000002.0001 | REV. D

Ethylene Plant

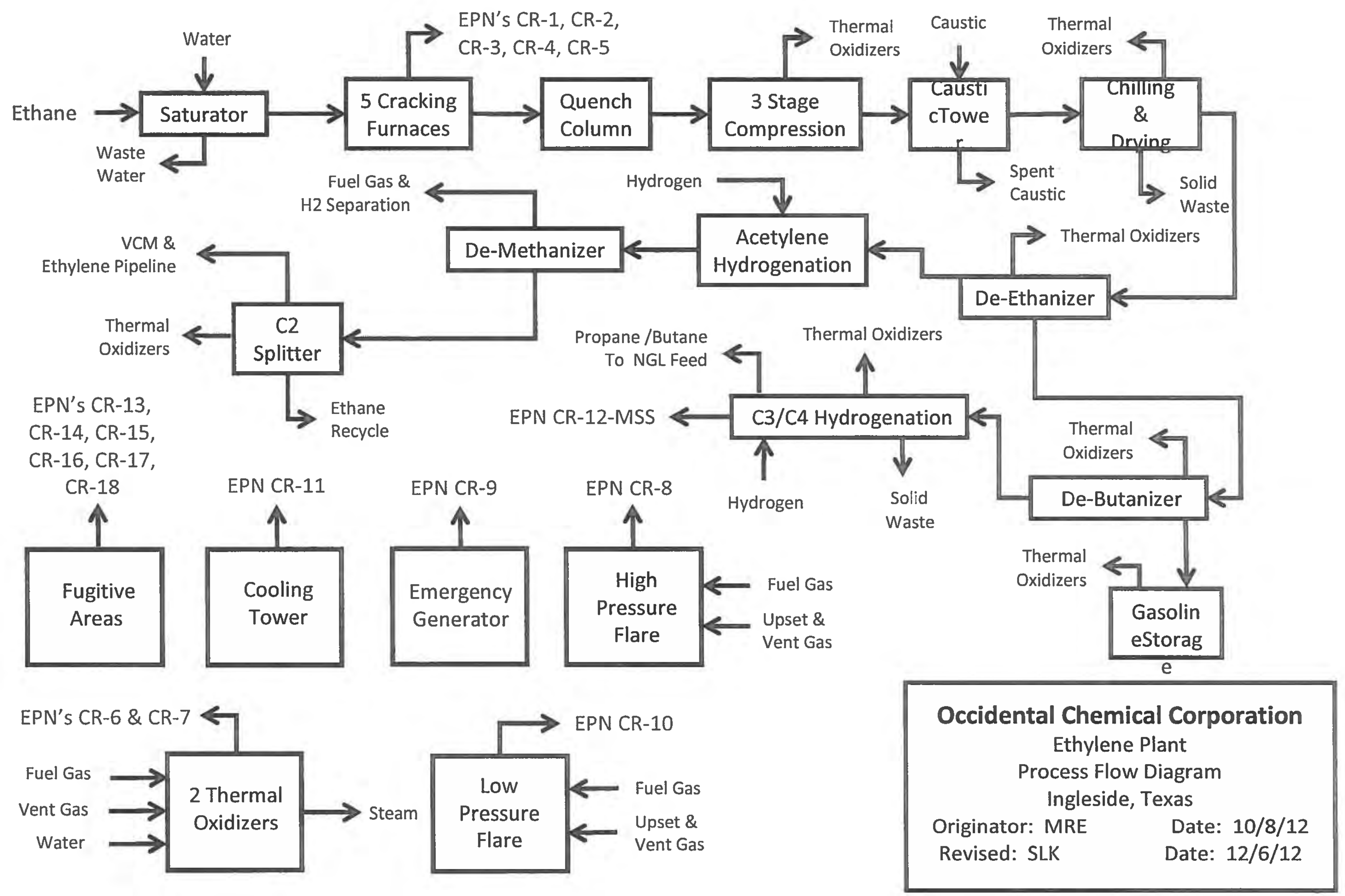


Table 2
Material Balance

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 flow diagram) to each material.

List Every Material Involved in Each of the Following Groups	Point Number from Flow Diagram	Process Rates (lb/hr or SCFM) Standard Conditions: 70 °F, 14.7 psia	Measurement	Estimation	Calculation
1. Raw Materials - Input					
Ethane Feed		185,000 lb/hr		X	
2. Fuels - Input					
Natural Gas		61,000 lb/hr		X	
Fuel Gas		28,800 lb/hr		X	
3. Products & Byproducts - Output					
Ethylene		142,800 lb/hr		X	
Propane/Butane Mix		9,700 lb/hr		X	
PyGas (Gasoline)		4,000 lb/hr		X	
Fuel Gas		28,800 lb/hr		X	
4. Solid Wastes - Output					
Coke, Spent Dessiccant, Catalysts and Misc. Waste		280,000 lb/yr		X	
5. Liquid Wastes - Output					
Saturator Blowdown, Spent Caustic, Boiler Blowdown, Cooling Tower Blowdown, Rain and Wash Down Water		37,000 lb/hr		X	
6. Airborne Waste (Solid) - Output					
$PM/PM_{10}/PM_{2.5}$		See Table 1(a)		X	
7. Airborne Waste (Gaseous) - Output					
NO_x, CO, VOC, HAP, SO_2, H_2SO_4, NH_3, and Cl_2		See Table 1(a)		X	

Notes:

1) All information is preliminary and may change based on the vendor information and/or the final engineering design.

APPENDIX C
EMISSION CALCULATIONS

GHG Emissions Summary

EPN	Sources	Annual GHG Emissions (tons/yr)			Global Warming Potential Factors			Annual CO_2e Emissions (tons/yr)			
		CO_2	CH_4	N_2O	CO_2	CH_4	N_2O	CO_2-related CO_2e	CH_4-related CO_2e	N_2O-related CO_2e	Total CO_2e
CR-1	Ethane Cracking Furnace No. 1	140,817.01	7.97	1.59	1	21	310	140,817.01	167.43	494.31	141,478.75
CR-2	Ethane Cracking Furnace No. 2	140,817.01	7.97	1.59	1	21	310	140,817.01	167.43	494.31	141,478.75
CR-3	Ethane Cracking Furnace No. 3	140,817.01	7.97	1.59	1	21	310	140,817.01	167.43	494.31	141,478.75
CR-4	Ethane Cracking Furnace No. 4	140,817.01	7.97	1.59	1	21	310	140,817.01	167.43	494.31	141,478.75
CR-5	Ethane Cracking Furnace No. 5	140,817.01	7.97	1.59	1	21	310	140,817.01	167.43	494.31	141,478.75
CR-1-5-MSS	Ethane Cracking Furnace Nos. 1-5 - MSS Activities	na	na	na	1	21	310	0.00	0.00	0.00	0.00
CR-6	CR Thermal Oxidizer No. 1	53,938.77	2.31	0.45	1	21	310	53,938.77	48.49	140.76	54,128.02
CR-7	CR Thermal Oxidizer No. 2	53,938.77	2.31	0.45	1	21	310	53,938.77	48.49	140.76	54,128.02
CR-8	CR High Pressure Flare	842.24	0.02	0.00	1	21	310	842.24	0.33	0.49	843.07
CR-8-MSS	CR High Pressure Flare - MSS Activities	69,541.37	3.65	0.73	1	21	310	69,541.37	76.65	226.29	69,844.31
CR-9	CR Emergency Generator Diesel Engine	61.44	0.00	0.00	1	21	310	61.44	0.05	0.15	61.65
CR-10	CR Low Pressure Flare	168.45	0.00	0.00	1	21	310	168.45	0.07	0.10	168.61
CR-10-MSS	CR Low Pressure Flare - MSS Activities	1078.78	0.05	0.01	1	21	310	1,078.78	0.97	2.82	1,082.56
CR-11	CR Cooling Tower	802.09	0.00	0.00	1	21	310	802.09	0.00	0.00	802.09
CR-12-MSS	C3/C4 Hydrogenation Regen. Vent - MSS Activities	12.93	0.00	0.00	1	21	310	12.93	0.03	0.06	13.02
CR-13	CR Furnace Area Fugitives	0.01	1.35	0.00	1	21	310	0.01	28.39	0.00	28.40
CR-14	CR Charge Gas Area Fugitives	0.00	0.42	0.00	1	21	310	0.00	8.78	0.00	8.79
CR-15	CR Recovery Area Fugitives	0.00	1.12	0.00	1	21	310	0.00	23.59	0.00	23.59
CR-16	CR C3+ Area Fugitives	0.00	0.26	0.00	1	21	310	0.00	5.42	0.00	5.42
CG-1 and CG-2	Cogeneration Units	110,093.30	2.08	0.21	1	21	310	110,093.30	43.61	64.37	110,201.27
Totals								994,563.21	1,121.99	3,047.34	998,732.54

Ethane Cracking Furnace Nos. 1-5

EPN's CR-1, CR-2, CR-3, CR-4 and CR-5

Estimated Emissions Based on Maximum Natural Gas Firing
(Worst-Case Calculations for Furnace CO2)

Basis:

275 MM Btu/hr, maximum, total natural gas fuel firing rate
116.91 lb/MM Btu, CO2 factor for natural gas from 40 CFR 98, Subpart C, Table C-1 (converted from 53.02 kg/MM Btu for use with Eq. C-1b)
0.002 lb/MM Btu, CH4 factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.001 kg/MM Btu for use with Eq. C-8b)
0.0002 lb/MM Btu, N2O factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0001 kg/MM Btu for use with Eq. C-8b)
8,760 hr/yr, hours of operation
Emission calculations below represent maximum emissions for each of the five furnaces

Pollutant	Emission Factor (lb/MM Btu)	Hourly Emissions (lb/hr)	Annual Emissions (tons/yr)
CO_2	116.91	32,150.00	140,817.01
CH_4	0.002	0.61	2.66
N_2O	0.0002	0.06	0.27

Calculation methods:

Hourly emissions (lb/hr) = emission factor (lb/MM Btu) x fuel firing rate (MM Btu/hr)
Annual emissions (tons/yr) = hourly emissions (lb/hr) x hours of operation (hr/yr) x 1 ton/2,000 lb

Ethane Cracking Furnace Nos. 1-5

EPN's CR-1, CR-2, CR-3, CR-4 and CR-5

Estimated Emissions Based on Maximum Process-Generated Fuel Gas (Hydrogen) Firing (Worst-Case Calculations for Furnace CH4 and N2O)

Basis:

275 MM Btu/hr, maximum process-generated fuel gas firing rate
Calculation of CO2 based on carbon balance for fuel gas (see nominal fuel gas speciation below)
0.007 lb/MM Btu, CH4 factor for petroleum fuel from 40 CFR 98, Subpart C, Table C-2
(converted from 0.003 kg/MM Btu for use with Eq. C-8b)
0.001 lb/MM Btu, N2O factor for petroleum fuel from 40 CFR 98, Subpart C, Table C-2
(converted from 0.0006 kg/MM Btu for use with Eq. C-8b)
8,760 hr/yr, hours of operation
Emission calculations below represent maximum emissions for each of the five furnaces

Fuel Gas Component	Molecular Weight (lb/lb mole)	Higher Heating Value (Btu/lb)	Max Firing Rate (lb/hr)	Annual Fuel Firing Rate (MM Btu/yr)	No. of Carbons per Molecule	Annual CO_2 Emissions (tons/yr)
Methane	16.04	23,900	4658.56	975,335	1	55,985.15
Ethane	30.07	22,336	4.76	931	2	61.03
Ethylene	28.10	21,651	108.64	20,605	2	1,490.52
Hydrogen	2.00	60,828	2644.40	1,409,077	0	0.00
Carbon Monoxide	28.01	4,346	119.37	4,545	1	821.50
Totals				2,410,493		58,358.20
Pollutants			**Emission Factor (lb/MM Btu)**	**Total Heating Value (MM Btu/yr)**		**Annual Emissions (tons/yr)**
CH_4			0.007	2,410,493		7.97
N_2O			0.001	2,410,493		1.59

Calculation methods:

Annual CO2 emissions (tons/yr) = fuel gas mass rate (lb/hr) x MW_{CO2} / MW_{VOC} x no. of carbons x 1 ton/2,000 lb x 8,760 hr/yr
Annual fuel gas emissions (tons/yr) = emission factor (lb/MM Btu) x annual fuel firing rate (MM Btu/yr) x 1 ton/2,000 lb

Ethane Cracking Furnace Nos. 1-5 - MSS Activities

EPN's CR-1-MSS, CR-2-MSS, CR-3-MSS, CR-4-MSS and CR-5-MSS

Estimated Emissions Based on Expected Coke Burn-Off

Basis:

Calculation of CO2 based on Equation Y-8 of 40 CFR 98.253 for coke burn-off
Calculation of CH4 based on Equation Y-9 of 40 CFR 98.253 for coke burn-off
(the CO2 estimate times the ration of CO2/CH4 default factors)
Calculation of N2O based on Equation Y-9 of 40 CFR 98.253 for coke burn-off
(the CO2 estimate times the ration of CO2/N2O default factors)
5,000 lb coke removed during each decoke event
0.94 default carbon content of coke per 40 CFR 98.253 Equation Y-8
102.04 kg CO2/MM Btu default CO2 factor for coke combustion from 40 CFR 98 Table C-1
0.011 kg CH4/MM Btu default CH4 factor for coke combustion from 40 CFR 98 Table C-2
0.0016 kg N2O/MM Btu default N2O factor for coke combustion from 40 CFR 98 Table C-2
48 hr/decoke event
36 decoke events/yr
Annual emission calculations below represent maximum emissions for all five furnaces

Pollutant	Coke Burn-Off (lb/decoke)	Coke Molecular Weight (lb/lb mole)	Annual Emissions (tons/yr)	Hourly Emissions (lb/hr)
CO_2	5,000	12.00	310.20	359.03
CH_4	na	na	0.033	0.039
N_2O	na	na	0.005	0.006

Emission comparisons:

Source of CO2 Emissions	Annual Emissions (tons/yr)	Hours of Operation (hr/event)	Hourly Emissions (lb/hr)	Comments
CO_2 from Coke Combustion	310	1,728	359	
CO_2 from Natural Gas	140,817	8,760	32,150	Worst-case hourly emissions
CO_2 from Process Fuel Gas	58,358	8,760	13,324	

Calculation methods:

Annual CO2 emissions (tons/yr) = coke mass rate (lb/event) x MW_{CO2} / MW_C x carbon content x no. of decoke events/yr x 1 ton/2,000 lb
Annual CH4 emissions (tons/yr) = CO2 emission rate (tons/yr) x default coke CH4 factor / default coke CO2 factor
Annual N2O emissions (tons/yr) = CO2 emission rate (tons/yr) x default coke N2O factor / default coke CO2 factor
Hourly emissions (lb/hr) = annual emissions (tons/yr) x 2,000 lb/ton x yr/no. of events (yr/event) x event/no. of hr (event/hr)

Conclusion:

Since hourly decoking CO2 emissions are less than hourly normal CO2 emissions, worst-case annual emissions do not include decoking contributions. The same is true for CH4 and N2O emissions.

CR Thermal Oxidizer Nos. 1 and 2

EPN's CR-6 and CR-7

Basis:

8.00 MM Btu/hr, core natural gas burner fuel firing rate
116.91 lb/MM Btu, CO2 factor for natural gas from 40 CFR 98, Subpart C, Table C-1 (converted from 53.02 kg/MM Btu for use with Eq. C-1b)
Calculation of CO2 based on carbon balance for process waste gas (see nominal process waste gas speciation below)
7.40 lb/hr CO2 contained in waste gas sent to the oxidizers
0.002 lb/MM Btu, CH4 factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.001 kg/MM Btu for use with Eq. C-8b)
0.0002 lb/MM Btu, N2O factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0001 kg/MM Btu for use with Eq. C-8b)
0.007 lb/MM Btu, CH4 factor for petroleum fuel from 40 CFR 98, Subpart C, Table C-2 (converted from 0.003 kg/MM Btu for use with Eq. C-8b)
0.001 lb/MM Btu, N2O factor for petroleum fuel from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0006 kg/MM Btu for use with Eq. C-8b)
8,760 hr/yr, hours of operation
Emission calculations below represent maximum emissions for each of the two thermal oxidizers

Pollutant	Molecular Weight (lb/lb mole)	Higher Heating Value (Btu/scf)	Higher Heating Value (Btu/lb)	Normal Venting (lb/hr)	Total Heating Value (MM Btu/yr)	No. of Carbons per Molecule	Annual CO_2 Emissions (tons/yr)
Hydrogen	2.00	321.0	60,830	27.73	14,777	0	0.00
Carbon Monoxide	28.00	321.1	4,346	0.72	27	1	4.96
Methane	16.04	1,011.5	23,900	230.30	48,217	1	2,767.68
Acetylene	26.04	1,475.8	21,479	1.13	213	2	16.75
Ethylene	28.06	1,603.0	21,651	442.60	83,944	2	6,081.03
Ethane	30.07	1,772.1	22,336	276.94	54,187	2	3,550.65
MAPD	18.90	1,038.0	20,815	2.91	531	3	89.10
Propylene	42.08	2,338.0	21,058	106.76	19,694	3	1,467.20
Propane	44.09	2,521.6	21,676	26.73	5,076	3	350.62
Butadienes	54.09	2,945.7	20,640	201.50	36,432	4	2,872.38
Butylenes	56.01	3,073.3	20,796	12.63	2,301	4	173.91
Butanes	58.12	3,268.4	21,312	16.69	3,116	4	221.42
C5's	72.15	4,017.0	21,101	815.62	150,764	5	10,895.56
C6-C8 Non-Aromatics	100.20	5,540.6	20,956	652.86	119,849	7	8,791.46
Benzene	78.11	3,749.1	18,190	746.49	118,949	6	11,052.80
Toluene	92.14	4,483.3	18,441	76.39	12,339	7	1,118.61
Xylene/Ethylene Benzene	106.16	5,218.1	18,629	7.78	1,270	8	113.03
Styrene	104.15	5,040.4	18,342	6.92	1,112	8	102.48
C9-204°C	128.30	7,012.2	20,714	9.71	1,762	9	131.31
204°C Plus	130.00	7,109.5	20,727	0.94	170	10	13.91
Totals					674,731		49,809.87
Pollutant				**Emission Factor (lb/MM Btu)**	**Total Heating Value (MM Btu/yr)**	**Hourly Emissions (lb/hr)**	**Annual Emissions (tons/yr)**
CO_2 - natural gas				116.91	70,080		4,096.49
CO_2 - waste gas combustion							49,809.87
CO_2 - process gas						7.40	32.41
CO_2 - total							53,938.77
CH_4 - natural gas				0.002	70,080		0.08
CH_4 - waste gas combustion				0.007	674,731		2.23
CH_4 - total							2.31
N_2O - natural gas				0.0002	70,080		0.01
N_2O - waste gas comb.				0.001	674,731		0.45
N_2O - total							0.45

Calculation methods:

Annual CO2 emissions (tons/yr) = natural gas emission factor (lb/MM Btu) x natural gas fuel firing rate (MM Btu/yr) x hours of operation (hr/yr) x 1 ton/2,000 lb + annual waste gas combustion-related CO2 (tons/yr) + process CO2 gas (lb/hr) x hours of operation (hr/yr) x 1 ton/2,000 lb
Annual CH4 and N2O emissions (tons/yr) = natural gas emission factor (lb/MM Btu) x natural gas fuel firing rate (MM Btu/yr) x hours of operation (hr/yr) x 1 ton/2,000 lb + petroleum fuel gas emission factor (lb/MM Btu) x total heating value of waste as (MM Btu/yr) x 1 ton/2,000 lb

Notes:

MAPD = Methyl Acetylene/Propadiene

CR High Pressure Flare

EPN CR-8

Basis:

80	scfh, natural gas input to a single flare pilot
0.001028	MM Btu/scf default natural gas heating value from 40 CFR 98, Subpart C, Table C-1
116.91	lb/MM Btu, CO2 factor for natural gas from 40 CFR 98, Subpart C, Table C-1 (converted from 53.02 kg/MM Btu for use with Eq. C-1)
0.002	lb/MM Btu, CH4 factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.001 kg/MM Btu for use with Eq. C-8)
0.0002	lb/MM Btu, N2O factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0001 kg/MM Btu for use with Eq. C-8)
20	number of pilots
8,760	hr/yr, hours of operation

Pollutant	Emission Factor (lb/MM Btu)	Hourly Emissions (lb/hr)	Annual Emissions (tons/yr)
CO_2	116.91	192.29	842.24
CH_4	0.002	0.0036	0.016
N_2O	0.0002	0.00036	0.0016

Calculation methods:

Hourly emissions (lb/hr) = emission factor (lb/MM Btu) x gas input per pilot (scfh) x default heating value (MM Btu/scf) x no. of pilots
Annual emissions (tons/yr) = hourly emissions (lb/hr) x 1 ton/2,000 lb x 8,760 hr/yr

CR High Pressure Flare - MSS Activities

EPN's CR-8-MSS

Basis:

Calculation of CO2 based on carbon balance for process waste gas (see nominal process waste gas speciation below)
0.007 lb/MM Btu, CH4 factor for petroleum fuel from 40 CFR 98, Subpart C, Table C-2 (converted from 0.003 kg/MM Btu for use with Eq. C-8b)
0.001 lb/MM Btu, N2O factor for petroleum fuel from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0006 kg/MM Btu for use with Eq. C-8b)
288 hr/yr, hours of start-up operation
16 hr/yr, hours of shutdown operation
It should be noted that the number of events, gas input mass rates and hours per event are provided for calculation purposes only; these parameters could change, but the annual emission rates will not be exceeded.

Start-up Emissions:

Pollutant	Molecular Weight (lb/lb mole)	Higher Heating Value (Btu/scf)	Higher Heating Value (Btu/lb)	Start-up Venting (lb/hr)	Total Heating Value (MM Btu/yr)	No. of Carbons per Molecule	Annual CO_2 Emissions (tons/yr)
Hydrogen	2.00	321.0	60,830	5,881.81	103,043	0	0.00
Carbon Monoxide	28.00	335.1	4,536	250.80	328	1	56.77
Carbon Dioxide	44.01	0.0	0	262.46	0	1	37.79
Hydrogen Sulfide	26.04	488.3	7,107	15.07	31	0	0.00
Methane	16.04	1,011.5	23,900	9,810.79	67,530	1	3,876.27
Acetylene	26.04	1,475.8	21,479	635.58	3,932	2	309.37
Ethylene	28.06	1,603.0	21,651	78,485.22	489,394	2	35,452.27
Ethane	30.07	1,772.1	22,336	52,649.74	338,684	2	22,192.52
MAPD	40.06	2,200.1	20,815	77.33	464	3	36.70
Propylene	40.08	2,226.9	21,058	1,998.59	12,121	3	948.05
Propane	44.09	2,521.6	21,676	461.78	2,883	3	199.13
Butadienes	54.09	2,945.7	20,640	2,156.44	12,819	4	1,010.63
Butylenes	56.10	3,078.2	20,796	299.09	1,791	4	135.15
Butanes	58.12	3,268.2	21,312	362.56	2,225	4	158.14
C5's	72.15	4,017.0	21,101	657.69	3,997	5	288.85
C6's Non-Aromatics	86.18	4,765.1	20,956	561.88	3,391	6	247.91
C7's Non-Aromatics	100.20	5,513.1	20,853	124.63	748	7	55.18
C8's Non-Aromatics	114.23	6,284.8	20,852	90.64	544	8	40.23
Benzene	78.11	3,748.9	18,190	1,110.23	5,816	6	540.47
Toluene	92.14	4,483.3	18,441	352.22	1,871	7	169.58
Xylene/ EB	106.16	5,218.1	18,629	148.94	799	8	71.13
Styrene	104.15	5,040.4	18,342	33.99	180	8	16.55
C9-204°C	128.30	7,012.2	20,714	151.25	902	9	67.24
204°C Plus	130.00	7,109.5	20,727	23.76	142	10	11.58
Totals					1,053,633		65,921.50
				Emission Factor (lb/MM Btu)	Total Heating Value (MM Btu/yr)	Hourly Emissions (lb/hr)	Annual Start-up Emissions (tons/yr)
CH_4				0.007	1,053,633		3.48
N_2O				0.001	1,053,633		0.70

Continued on next page.

CR High Pressure Flare - MSS Activities (cont'd)

EPN's CR-8-MSS

Shutdown Emissions:

Pollutant	Molecular Weight (lb/lb mole)	Higher Heating Value (Btu/scf)	Higher Heating Value (Btu/lb)	Shutdown Venting (lb/hr)	Total Heating Value (MM Btu/yr)	No. of Carbons per Molecule	Annual CO_2 Emissions (tons/yr)
Hydrogen	2.00	321.0	60,830	3.82	4	0	0.00
Carbon Monoxide	28.00	335.1	4,536	3.26	0	1	0.04
Carbon Dioxide	44.01	0.0	0	0.00	0	1	0.00
Hydrogen Sulfide	26.04	488.3	7,107	0.00	0	0	0.00
Methane	16.04	1,011.5	23,900	6,150.98	2,352	1	135.01
Acetylene	26.04	1,475.8	21,479	0.00	0	2	0.00
Ethylene	28.06	1,603.0	21,651	46,676.73	16,170	2	1,171.34
Ethane	30.07	1,772.1	22,336	30,482.69	10,894	2	713.82
MAPD	40.06	2,200.1	20,815	58.53	19	3	1.54
Propylene	40.08	2,226.9	21,058	56,379.14	18,996	3	1,485.78
Propane	44.09	2,521.6	21,676	594.93	206	3	14.25
Butadienes	54.09	2,945.7	20,640	1,621.93	536	4	42.23
Butylenes	56.10	3,078.2	20,796	225.08	75	4	5.65
Butanes	58.12	3,268.2	21,312	273.07	93	4	6.62
C5's	72.15	4,017.0	21,101	411.92	139	5	10.05
C6's Non-Aromatics	86.18	4,765.1	20,956	324.98	109	6	7.97
C7's Non-Aromatics	100.20	5,513.1	20,853	65.57	22	7	1.61
C8's Non-Aromatics	114.23	6,284.8	20,852	38.08	13	8	0.94
Benzene	78.11	3,748.9	18,190	611.99	178	6	16.55
Toluene	92.14	4,483.3	18,441	162.16	48	7	4.34
Xylene/ EB	106.16	5,218.1	18,629	48.46	14	8	1.29
Styrene	104.15	5,040.4	18,342	9.85	3	8	0.27
C9-Plus	128.30	7,012.2	20,714	23.22	8	9	0.57
Totals				144,166.39	49,878		3,619.87
Pollutant				**Emission Factor (lb/MM Btu)**	**Total Heating Value (MM Btu/yr)**	**Hourly Emissions (lb/hr)**	**Annual Shutdown Emissions (tons/yr)**
CH_4				0.007	49,878		0.16
N_2O				0.001	49,878		0.03

Total MSS Emissions:

Pollutant					Annual Start-up Emissions (tons/yr)	Annual Shutdown Emissions (tons/yr)	Total Annual Emissions (tons/yr)
CO_2					65,921.50	3,619.87	69,541.37
CH_4					3.48	0.16	3.65
N_2O					0.70	0.03	0.73

Calculation methods:

Annual CO2 emissions (tons/yr) = vent gas (lb/hr) x MW_{CO2} / MW_{VOC} x no. of carbons x 1 ton/2,000 lb x 8,760 hr/yr
Annual CH4 and N2O emissions (tons/yr) = emission factor (lb/MM Btu) x fuel firing rate (MM Btu/hr) x 1 ton/2,000 lb x 8,760 hr/yr

Notes:

MAPD = Methyl Acetylene/Propadiene

CR Emergency Generator Diesel Engine
EPN CR-9

Basis:

105 gal/hr of diesel fired in 2,206 HP engine
0.138 MM Btu/gal diesel heating value
163.08 lb/MM Btu, CO2 factor for diesel from 40 CFR 98, Subpart C, Table C-1 (converted from 73.96 kg/MM Btu)
0.007 lb/MM Btu, CH4 factor for diesel from 40 CFR 98, Subpart C, Table C-2 (converted from 0.003 kg/MM Btu)
0.001 lb/MM Btu, N2O factor for diesel from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0006 kg/MM Btu)
52 hr/yr, hours of operation

Engine	Pollutant	Emission Factor (lb/MM Btu)	Emissions (tons/yr)
CR-9 Emergency Generator Diesel Engine	CO_2	163.08	61.4394
	CH_4	0.007	0.0025
	N_2O	0.001	0.0005

Calculation methods:

Annual emissions (tons/yr) = emission factor (lb/MM Btu) x diesel consumption (gal/hr) x heat content (MM Btu/gal) x hours of operation (hr/yr) x 1 ton/2,000 lb

CR Low Pressure Flare

EPN CR-10

Basis:

80 scfh, natural gas input to a single flare pilot
0.001028 MM Btu/scf default natural gas heating value from 40 CFR 98, Subpart C, Table C-1
116.91 lb/MM Btu, CO2 factor for natural gas from 40 CFR 98, Subpart C, Table C-1 (converted from 53.02 kg/MM Btu for use with Eq. C-1)
0.002 lb/MM Btu, CH4 factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.001 kg/MM Btu for use with Eq. C-8)
0.0002 lb/MM Btu, N2O factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0001 kg/MM Btu for use with Eq. C-8)
4 number of pilots
8,760 hr/yr, hours of operation

Pollutant	Emission Factor (lb/MM Btu)	Hourly Emissions (lb/hr)	Annual Emissions (tons/yr)
CO_2	116.91	38.46	168.45
CH_4	0.002	0.0007	0.003
N_2O	0.0002	0.00007	0.0003

Calculation methods:

Hourly emissions (lb/hr) = emission factor (lb/MM Btu) x gas input per pilot (scfh) x default heating value (MM Btu/scf) x no. of pilots
Annual emissions (tons/yr) = hourly emissions (lb/hr) x 1 ton/2,000 lb x 8,760 hr/yr

CR Low Pressure Flare MSS Activities
EPN CR-10-MSS

Basis:

2 % of thermal oxidizer emissions considered as possible MSS emissions for the rare occurrence that both oxidizers are out of service
8.00 MM Btu/hr, core natural gas burner fuel firing rate
116.91 lb/MM Btu, CO2 factor for natural gas from 40 CFR 98, Subpart C, Table C-1 (converted from 53.02 kg/MM Btu for use with Eq. C-1b)
Calculation of CO2 based on carbon balance for process waste gas (see nominal process waste gas speciation below)
7.40 lb/hr CO2 contained in waste gas sent to the oxidizers
0.002 lb/MM Btu, CH4 factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.001 kg/MM Btu for use with Eq. C-8b)
0.0002 lb/MM Btu, N2O factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0001 kg/MM Btu for use with Eq. C-8b)
0.007 lb/MM Btu, CH4 factor for petroleum fuel from 40 CFR 98, Subpart C, Table C-2 (converted from 0.003 kg/MM Btu for use with Eq. C-8b)
0.001 lb/MM Btu, N2O factor for petroleum fuel from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0006 kg/MM Btu for use with Eq. C-8l
8,760 hr/yr, hours of operation

Thermal Oxidizer Emissions:

Pollutant	Molecular Weight (lb/lb mole)	Higher Heating Value (Btu/scf @60 F)	Higher Heating Value (Btu/lb)	Normal Venting (lb/hr)	Total Heating Value (MM Btu/yr)	No. of Carbons per Molecule	Annual CO_2 Emissions (tons/yr)
Hydrogen	2.00	321.0	60,830	27.73	14,777	0	0.00
Carbon Monoxide	28.00	321.1	4,346	0.72	27	1	4.96
Methane	16.04	1,011.5	23,900	230.30	48,217	1	2,767.68
Acetylene	26.04	1,475.8	21,479	1.13	213	2	16.75
Ethylene	28.06	1,603.0	21,651	442.60	83,944	2	6,081.03
Ethane	30.07	1,772.1	22,336	276.94	54,187	2	3,550.65
MAPD	18.90	1,038.0	20,815	2.91	531	3	89.10
Propylene	42.08	2,338.0	21,058	106.76	19,694	3	1,467.20
Propane	44.09	2,521.6	21,676	26.73	5,076	3	350.62
Butadienes	54.09	2,945.7	20,640	201.50	36,432	4	2,872.38
Butylenes	56.01	3,073.3	20,796	12.63	2,301	4	173.91
Butanes	58.12	3,268.4	21,312	16.69	3,116	4	221.42
C5's	72.15	4,017.0	21,101	815.62	150,764	5	10,895.56
C6-C8 Non-Aromatics	100.20	5,540.6	20,956	652.86	119,849	7	8,791.46
Benzene	78.11	3,749.1	18,190	746.49	118,949	6	11,052.80
Toluene	92.14	4,483.3	18,441	76.39	12,339	7	1,118.61
Xylene/Ethylene Benzene	106.16	5,218.1	18,629	7.78	1,270	8	113.03
Styrene	104.15	5,040.4	18,342	6.92	1,112	8	102.48
C9-204 C	128.30	7,012.2	20,714	9.71	1,762	9	131.31
204-288 C	130.00	7,109.5	20,727	0.94	170	10	13.91
Totals					674,731		49,809.87
Pollutant				**Emission Factor (lb/MM Btu)**	**Total Heating Value (MM Btu/yr)**	**Hourly Emissions (lb/hr)**	**Annual Emissions (tons/yr)**
CO_2 - fuel gas				116.91	70,080		4,096.49
CO_2 - waste gas combustion							49,809.87
CO_2 - process gas						7.40	32.41
CO_2 - total							53,938.77
CH_4 - fuel gas				0.002	70,080		0.08
CH_4 - waste gas combustion				0.007	674,731		2.23
CH_4 - total							2.31
N_2O - fuel gas				0.0002	70,080		0.01
N_2O - waste gas comb.				0.001	674,731		0.45
N_2O - total							0.45
Pollutant						**Oxidizer Annual Emissions (tons/yr)**	**Flare MSS Annual Emissions (tons/yr)**
CO_2 - MSS only						53,938.77	1,078.78
CH_4 - MSS only						2.31	0.05
N_2O - MSS only						0.45	0.01

Calculation methods:

Annual thermal oxidizer emissions (tons/yr) - see CR-6 and CR-7
Annual emissions (tons/yr) = annual thermal oxidizer emissions (tons/yr) x 2%

CR Cooling Tower

EPN CR-11

Basis:

1,154,000 lb/hr make-up water
220 ppmw bicarbonate (HCO3) equivalent concentration representing make-up water alkalinity
61 lb/lb mole, molecular weight of HCO3
one mole of CO2 released per mole of HCO3
44 lb/lb mole, molecular weight of CO2
8,760 hr/yr, hours of operation

Pollutant	HCO_3 Loading in Make-up Water (lb/hr)	CO_2 Hourly Emissions (lb/hr)	Annual CO_2 Emissions (tons/yr)
CO_2	253.88	183.13	802.09

Calculation methods:

HCO3 loading (lb/hr) = make-up water (lb/hr) x bicarbonate equivalent concentration (ppmw)
Hourly CO2 emissions (lb/hr) = HCO3 loading (lb/hr) x MW CO2 (lb/lb mole) x 1/MW HCO3 (lb/lb mole)
Annual CO2 emissions (tons/yr) = hourly emissions (lb/hr) x 1 ton/2,000 lb x 8,760 hr/yr

C3/C4 Hydrogenation Regeneration Vent - MSS Activities

EPN CR-12-MSS

Basis:

Calculation of CO2 based on Equation Y-8 of 40 CFR 98.253 for coke burn-off
Calculation of CH4 based on Equation Y-9 of 40 CFR 98.253 for coke burn-off
(the CO2 estimate times the ration of CO2/CH4 default factors)
Calculation of N2O based on Equation Y-10 of 40 CFR 98.253 for coke burn-off
(the CO2 estimate times the ration of CO2/N2O default factors)

3,600	lb coke removed during each decoke event
0.94	default carbon content of coke per 40 CFR 98.253 Equation Y-8
102.04	kg CO2/MM Btu default CO2 factor for coke combustion from 40 CFR 98 Table C-1
0.011	kg CH4/MM Btu default CH4 factor for coke combustion from 40 CFR 98 Table C-2
0.0016	kg N2O/MM Btu default N2O factor for coke combustion from 40 CFR 98 Table C-2
48	hr/decoke event
100	hr/yr, hours of operation per year

Pollutant	Coke Burn-Off (lb/decoke)	Coke Molecular Weight (lb/lb mole)	Annual Emissions (tons/yr)
CO_2	3,600	12.00	12.93
CH_4	na	na	0.001
N_2O	na	na	0.000

Calculation methods:

Annual CO2 emissions (tons/yr) = coke mass rate (lb/event) x MW_{CO2} / MW_C x carbon content x hr of decoke events/yr (hr/yr) x decoke event/hr (event/hr) x 1 ton/2,000 lb
Annual CH4 emissions (tons/yr) = CO2 emission rate (tons/yr) x default coke CH4 factor / default coke CO2 factor
Annual N2O emissions (tons/yr) = CO2 emission rate (tons/yr) x default coke N2O factor / default coke CO2 factor

Ethylene Plant Fugitive Emission Totals
CR Furnace Area Fugitives, CR-13

Constituents	Ethane Feed (Comp B): 4010 Pipeline Ethane Feed		Saturated C2 (Comp C): Nos. 1-5 Furnace Feeds; Feed Saturator Vapor		Furnace Outlet (Comp D): Nos. 1-5 Furnace Outlets		Quench Overhead (Comp E): Quench Column Liquid Gasoline		Quench Gasoline (Comp F): Quench Column Liquid Gasoline		Quench Water (Comp G): Feed Saturator Water; Quench Water; Process Water Treatment	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	0.0783	1.0000	0.2038	1.0000	0.3586	1.0000	0.0179	1.0000	0.0336	1.0000	0.1261
Hydrogen	0.000000	0.0000	0.000000	0.0000	0.269900	0.0968	0.339000	0.0061	0.000000	0.0000	0.000000	0.0000
Carbon Monoxide	0.000000	0.0000	0.000000	0.0000	0.000800	0.0003	0.001000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Dioxide	0.000100	0.0000	0.000100	0.0000	0.000300	0.0001	0.000300	0.0000	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.025000	0.0020	0.015000	0.0031	0.054500	0.0195	0.068400	0.0012	0.000000	0.0000	0.000000	0.0000
Acetylene	0.000000	0.0000	0.000000	0.0000	0.002300	0.0008	0.002800	0.0001	0.000000	0.0000	0.000000	0.0000
Ethylene	0.000000	0.0000	0.002000	0.0004	0.259300	0.0930	0.325800	0.0058	0.000000	0.0000	0.000100	0.0000
Ethane	0.949900	0.0744	0.633900	0.1292	0.161700	0.0580	0.203100	0.0036	0.000000	0.0000	0.000100	0.0000
Methyl Acetylene/Propadiene	0.000000	0.0000	0.000000	0.0000	0.000200	0.0001	0.000200	0.0000	0.000000	0.0000	0.000000	0.0000
Propylene	0.000000	0.0000	0.002000	0.0004	0.004600	0.0016	0.005800	0.0001	0.000000	0.0000	0.000000	0.0000
Propane	0.025000	0.0020	0.015000	0.0031	0.001000	0.0004	0.001200	0.0000	0.000000	0.0000	0.000000	0.0000
Butadienes	0.000000	0.0000	0.000000	0.0000	0.003700	0.0013	0.004700	0.0001	0.000500	0.0000	0.000000	0.0000
Butylenes	0.000000	0.0000	0.000000	0.0000	0.000500	0.0002	0.000600	0.0000	0.000100	0.0000	0.000000	0.0000
Butanes	0.000000	0.0000	0.000000	0.0000	0.000600	0.0002	0.000700	0.0000	0.000000	0.0000	0.000000	0.0000
C5's	0.000000	0.0000	0.000000	0.0000	0.000700	0.0003	0.001100	0.0000	0.135200	0.0045	0.000000	0.0000
C6-C8 Non-Aromatics	0.000000	0.0000	0.000000	0.0000	0.000600	0.0002	0.000900	0.0000	0.212600	0.0071	0.000000	0.0000
Benzene	0.000000	0.0000	0.000000	0.0000	0.001200	0.0004	0.001700	0.0000	0.498500	0.0167	0.000400	0.0001
Toluene	0.000000	0.0000	0.000000	0.0000	0.000200	0.0001	0.000200	0.0000	0.079400	0.0027	0.000100	0.0000
Xylene/ Ethyl Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.008600	0.0003	0.000000	0.0000
Styrene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.016200	0.0005	0.000000	0.0000
C9 - 204 C	0.000000	0.0000	0.000000	0.0000	0.000100	0.0000	0.000100	0.0000	0.030400	0.0010	0.000000	0.0000
204 - 288 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.010100	0.0003	0.000000	0.0000
288 C+	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.008400	0.0003	0.000000	0.0000
Water	0.000000	0.0000	0.332000	0.0677	0.237800	0.0853	0.042300	0.0008	0.000000	0.0000	0.999300	0.1260
Nitrogen	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
DMS/DMDS	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.0783		0.2038		0.3586		0.0179		0.0336		0.1261

Column Totals, EPN CR-13

Carbon Monoxide		0.0000		0.0000		0.0003		0.0000		0.0000		0.0000
Carbon Dioxide		0.0000		0.0000		0.0001		0.0000		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Methane		0.0020		0.0031		0.0195		0.0012		0.0000		0.0000
Ethane		0.0744		0.1292		0.0580		0.0036		0.0000		0.0000
Hydrogen, Water and Nitrogen		0.0000		0.0677		0.1820		0.0068		0.0000		0.1260
Ammonia		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Total VOC		0.0020		0.0039		0.0986		0.0062		0.0336		0.0001
Totals		0.0783		0.2038		0.3586		0.0179		0.0336		0.1261

Ethylene Plant Fugitive Emission Totals
CR Furnace Area Fugitives, CR-13 (cont'd)

Constituents	Off-Gas to Fuel (Comp V): Nos. 1-5 Furnace Fuel Systems; Fuel Gas Blend System		Natural Gas (Comp AD): NG Dist System		Dimethyl Sulfide (Comp AE): Dimethyl Sulfide System - Liquid Service (or Dimethyl Disulfide)		Dimethyl Sulfide Vapor (Comp AF): Dimethyl Sulfide System - Vapor Service (or Dimethyl Disulfide)		Wash Oil (Comp AG): Wash Oil - Liquid Service		Wash Oil Vapor (Comp AG): Wash Oil - Vapor Service	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	0.7952	1.0000	0.1521	1.0000	0.0177	1.0000	0.0370	1.0000	0.0177	1.0000	0.0412
Hydrogen	0.819800	0.6519	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Monoxide	0.002700	0.0021	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Dioxide	0.000000	0.0000	0.012000	0.0018	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.175000	0.1392	0.945000	0.1437	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Acetylene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethylene	0.002400	0.0019	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethane	0.000100	0.0001	0.032000	0.0049	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methyl Acetylene/Propadiene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propylene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propane	0.000000	0.0000	0.008000	0.0012	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butadienes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butylenes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butanes	0.000000	0.0000	0.000500	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C5's	0.000000	0.0000	0.000400	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C6-C8 Non-Aromatics	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Toluene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Xylene/ Ethyl Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Styrene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C9 - 204 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	1.000000	0.0177	0.007000	0.0003
204 - 288 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
288 C+	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Water	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Nitrogen	0.000000	0.0000	0.002000	0.0003	0.000000	0.0000	0.360000	0.0133	0.000000	0.0000	0.993000	0.0409
DMS/DMDS	0.000000	0.0000	0.000000	0.0000	1.000000	0.0177	0.640000	0.0237	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.7952		0.1521		0.0177		0.0370		0.0177		0.0412

Column Totals, EPN CR-13

Carbon Monoxide		0.0021		0.0000		0.0000		0.0000		0.0000		0.0000
Carbon Dioxide		0.0000		0.0018		0.0000		0.0000		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Methane		0.1392		0.1437		0.0000		0.0000		0.0000		0.0000
Ethane		0.0001		0.0049		0.0000		0.0000		0.0000		0.0000
Hydrogen, Water and Nitrogen		0.6519		0.0003		0.0000		0.0133		0.0000		0.0409
Ammonia		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Total VOC		0.0019		0.0014		0.0177		0.0237		0.0177		0.0003
Totals		0.7952		0.1521		0.0177		0.0370		0.0177		0.0412

Ethylene Plant Fugitive Emission Totals
CR Furnace Area Fugitives, CR-13 (cont'd)

Constituents	Ammonia (Comp XX): Ammonia Systems	
	Weight Fraction	Emissions (lb/hr)
	1.0000	0.0642
Hydrogen	0.0000	0.0000
Carbon Monoxide	0.0000	0.0000
Carbon Dioxide	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000
Methane	0.0000	0.0000
Acetylene	0.0000	0.0000
Ethylene	0.0000	0.0000
Ethane	0.0000	0.0000
Methyl Acetylene/Propadiene	0.0000	0.0000
Propylene	0.0000	0.0000
Propane	0.0000	0.0000
Butadienes	0.0000	0.0000
Butylenes	0.0000	0.0000
Butanes	0.0000	0.0000
C5's	0.0000	0.0000
C6-C8 Non-Aromatics	0.0000	0.0000
Benzene	0.0000	0.0000
Toluene	0.0000	0.0000
Xylene/ Ethyl Benzene	0.0000	0.0000
Styrene	0.0000	0.0000
C9 - 204 C	0.0000	0.0000
204 - 288 C	0.0000	0.0000
288 C+	0.0000	0.0000
Water	0.0000	0.0000
Nitrogen	0.0000	0.0000
DMS/DMDS	0.0000	0.0000
Ammonia	1.0000	0.0642
Total		0.0642

Column Totals, EPN CR-13

Carbon Monoxide		0.0000
Carbon Dioxide		0.0000
Hydrogen Sulfide		0.0000
Methane		0.0000
Ethane		0.0000
Hydrogen, Water and Nitrogen		0.0000
Ammonia		0.0642
Total VOC		0.0000
Totals		0.0642

Ethylene Plant Fugitive Emission Totals
CR Charge Gas Area Fugitives, CR-14

Constituents	Quench Overhead (Comp E): Charge Gas Compressor - Vapor Service		Charge Gas Liquid (Comp H): Charge Gas Compressor - Liquid Service		Quench Water (Comp G): Caustic Tower Liquid		De-Butanizer Bottoms (Comp W): Caustic Gasoline Washing; Emergency Relief Header - Liquid Service		Natural Gas (Comp AD): Emergency Relief Header - Vapor Service	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	**0.2868**	**1.0000**	**0.0282**	**1.0000**	**0.0222**	**1.0000**	**0.0780**	**1.0000**	**0.0803**
Hydrogen	0.339000	0.0972	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Monoxide	0.001000	0.0003	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Dioxide	0.000300	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.012000	0.0010
Hydrogen Sulfide	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.068400	0.0196	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.945000	0.0758
Acetylene	0.002800	0.0008	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethylene	0.325800	0.0935	0.000100	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000
Ethane	0.203100	0.0583	0.000100	0.0000	0.000100	0.0000	0.000000	0.0000	0.032000	0.0026
Methyl Acetylene/Propadiene	0.000200	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propylene	0.005800	0.0017	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propane	0.001200	0.0003	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.008000	0.0006
Butadienes	0.004700	0.0013	0.000000	0.0000	0.000000	0.0000	0.000400	0.0000	0.000000	0.0000
Butylenes	0.000600	0.0002	0.000000	0.0000	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000
Butanes	0.000700	0.0002	0.000000	0.0000	0.000000	0.0000	0.000100	0.0000	0.000500	0.0000
C5's	0.001100	0.0003	0.000000	0.0000	0.000000	0.0000	0.235800	0.0184	0.000400	0.0000
C6-C8 Non-Aromatics	0.000900	0.0003	0.000100	0.0000	0.000000	0.0000	0.243600	0.0190	0.000100	0.0000
Benzene	0.001700	0.0005	0.000300	0.0000	0.000400	0.0000	0.431300	0.0336	0.000000	0.0000
Toluene	0.000200	0.0001	0.000100	0.0000	0.000100	0.0000	0.057400	0.0045	0.000000	0.0000
Xylene/ Ethyl Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.005500	0.0004	0.000000	0.0000
Styrene	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.010000	0.0008	0.000000	0.0000
C9 - 204 C	0.000100	0.0000	0.000400	0.0000	0.000000	0.0000	0.014600	0.0011	0.000000	0.0000
204 - 288 C	0.000000	0.0000	0.000400	0.0000	0.000000	0.0000	0.001200	0.0001	0.000000	0.0000
288 C+	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Water	0.042300	0.0121	0.998300	0.0282	0.999300	0.0222	0.000000	0.0000	0.000000	0.0000
Nitrogen	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.002000	0.0002
DMS/DMDS	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.2868		0.0282		0.0222		0.0780		0.0803

Column Totals, EPN CR-14

Carbon Monoxide		0.0003		0.0000		0.0000		0.0000		0.0000
Carbon Dioxide		0.0001		0.0000		0.0000		0.0000		0.0010
Hydrogen Sulfide		0.0000		0.0000		0.0000		0.0000		0.0000
Methane		0.0196		0.0000		0.0000		0.0000		0.0758
Ethane		0.0583		0.0000		0.0000		0.0000		0.0026
Hydrogen, Water and Nitrogen		0.1094		0.0282		0.0222		0.0000		0.0002
Ammonia		0.0000		0.0000		0.0000		0.0000		0.0000
Total VOC		0.0992		0.0000		0.0000		0.0780		0.0007
Totals		0.2868		0.0282		0.0222		0.0780		0.0803

Ethylene Plant Fugitive Emission Totals
CR Recovery Area Fugitives, CR-15

Constituents	Quench Overhead (Comp E): Charge Gas Drying - Vapor Service		Charge Gas Liquid (Comp H): Charge Gas Drying; Dryer Regeneration - All Liquid Service		Hydrogen Off-Gas (Comp N): Dryer Regeneration - Vapor Service		De-Methanizer Feed Vapor (Comp L): De-Methanizer Feed System - Vapor Service		De-Methanizer Liquid Feed (Comp M): De-Methanizer Feed System - Liquid Service		De-Methanizer Overhead Liquids (Comp O): De-Methanizer Overhead and Reflux	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	0.1718	1.0000	0.0090	1.0000	0.0739	1.0000	0.0717	1.0000	0.0225	1.0000	0.0598
Hydrogen	0.339000	0.0582	0.000000	0.0000	0.842500	0.0623	0.358300	0.0257	0.004800	0.0001	0.002500	0.0001
Carbon Monoxide	0.001000	0.0002	0.000000	0.0000	0.002500	0.0002	0.001100	0.0001	0.000300	0.0000	0.001200	0.0001
Carbon Dioxide	0.000300	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.068400	0.0118	0.000000	0.0000	0.152600	0.0113	0.072900	0.0052	0.143700	0.0032	0.936200	0.0560
Acetylene	0.002800	0.0005	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethylene	0.325800	0.0560	0.000100	0.0000	0.002300	0.0002	0.349300	0.0250	0.644900	0.0145	0.057600	0.0034
Ethane	0.203100	0.0349	0.000100	0.0000	0.000100	0.0000	0.217200	0.0156	0.206200	0.0046	0.002500	0.0001
Methyl Acetylene/Propadiene	0.000200	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propylene	0.005800	0.0010	0.000000	0.0000	0.000000	0.0000	0.001100	0.0001	0.000100	0.0000	0.000000	0.0000
Propane	0.001200	0.0002	0.000000	0.0000	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000
Butadienes	0.004700	0.0008	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butylenes	0.000600	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butanes	0.000700	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C5's	0.001100	0.0002	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C6-C8 Non-Aromatics	0.000900	0.0002	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Benzene	0.001700	0.0003	0.000300	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Toluene	0.000200	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Xylene/ Ethyl Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Styrene	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C9 - 204 C	0.000100	0.0000	0.000400	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
204 - 288 C	0.000000	0.0000	0.000400	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
288 C+	0.000000	0.0000	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Water	0.042300	0.0073	0.998300	0.0090	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Nitrogen	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
DMS/DMDS	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.1718		0.0090		0.0739		0.0717		0.0225		0.0598

Column Totals, EPN CR-15

Carbon Monoxide		0.0002		0.0000		0.0002		0.0001		0.0000		0.0001
Carbon Dioxide		0.0001		0.0000		0.0000		0.0000		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Methane		0.0118		0.0000		0.0113		0.0052		0.0032		0.0560
Ethane		0.0349		0.0000		0.0000		0.0156		0.0046		0.0001
Hydrogen, Water and Nitrogen		0.0655		0.0090		0.0623		0.0257		0.0001		0.0001
Ammonia		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Total VOC		0.0594		0.0000		0.0002		0.0251		0.0145		0.0034
Totals		0.1718		0.0090		0.0739		0.0717		0.0225		0.0598

Ethylene Plant Fugitive Emission Totals
CR Recovery Area Fugitives, CR-15 (cont'd)

Constituents	De-Methanizer Bottoms (Comp P): De-Methanizer Bottoms		AC Reactor Feed (Comp J): De-Ethanizer Overhead		De-Ethanizer Reflux (Comp K): De-Ethanizer Reflux		De-Ethanizer Bottoms (Comp I): De-Ethanizer Bottoms		Ethylene Product (Comp Q): Ethylene Fractionator Overhead		Ethylene Side Reboiler (Comp S): Ethylene Fractionator Side Reboiler	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	0.0575	1.0000	0.3122	1.0000	0.0268	1.0000	0.0498	1.0000	0.7779	1.0000	0.0274
Hydrogen	0.000000	0.0000	0.330600	0.1032	0.004000	0.0001	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Monoxide	0.000000	0.0000	0.001000	0.0003	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Dioxide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.000300	0.0000	0.067700	0.0211	0.013600	0.0004	0.000000	0.0000	0.000500	0.0004	0.000000	0.0000
Acetylene	0.000000	0.0000	0.002800	0.0009	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethylene	0.614600	0.0353	0.355200	0.1109	0.458200	0.0123	0.000100	0.0000	0.999000	0.7771	0.591100	0.0162
Ethane	0.383000	0.0220	0.240400	0.0751	0.509500	0.0137	0.000000	0.0000	0.000500	0.0004	0.408000	0.0112
Methyl Acetylene/Propadiene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.013900	0.0007	0.000000	0.0000	0.000000	0.0000
Propylene	0.001900	0.0001	0.002100	0.0007	0.012900	0.0003	0.284400	0.0142	0.000000	0.0000	0.000800	0.0000
Propane	0.000200	0.0000	0.000200	0.0001	0.001700	0.0000	0.091800	0.0046	0.000000	0.0000	0.000100	0.0000
Butadienes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.280100	0.0140	0.000000	0.0000	0.000000	0.0000
Butylenes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.037700	0.0019	0.000000	0.0000	0.000000	0.0000
Butanes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.049900	0.0025	0.000000	0.0000	0.000000	0.0000
C5's	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.066600	0.0033	0.000000	0.0000	0.000000	0.0000
C6-C8 Non-Aromatics	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.054800	0.0027	0.000000	0.0000	0.000000	0.0000
Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.100100	0.0050	0.000000	0.0000	0.000000	0.0000
Toluene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.013300	0.0007	0.000000	0.0000	0.000000	0.0000
Xylene/ Ethyl Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.001300	0.0001	0.000000	0.0000	0.000000	0.0000
Styrene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.002300	0.0001	0.000000	0.0000	0.000000	0.0000
C9 - 204 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.003400	0.0002	0.000000	0.0000	0.000000	0.0000
204 - 288 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000300	0.0000	0.000000	0.0000	0.000000	0.0000
288 C+	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Water	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Nitrogen	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
DMS/DMDS	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.0575		0.3122		0.0268		0.0498		0.7779		0.0274

Column Totals, EPN CR-15

Carbon Monoxide		0.0000		0.0003		0.0000		0.0000		0.0000		0.0000
Carbon Dioxide		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Methane		0.0000		0.0211		0.0004		0.0000		0.0004		0.0000
Ethane		0.0220		0.0751		0.0137		0.0000		0.0004		0.0112
Hydrogen, Water and Nitrogen		0.0000		0.1032		0.0001		0.0000		0.0000		0.0000
Ammonia		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Total VOC		0.0354		0.1125		0.0127		0.0498		0.7771		0.0162
Totals		0.0575		0.3122		0.0268		0.0498		0.7779		0.0274

Ethylene Plant Fugitive Emission Totals
CR Recovery Area Fugitives, CR-15 (cont'd)

Constituents	Ethane Recycle (Comp R): Ethylene Fractionator Bottoms; Recycle Ethane Storage		Propylene Refrigeration (Comp AB): Propylene Refrigeration		Binary Refrigeration (Comp AC): Binary Refrigeration	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	**0.0967**	**1.0000**	**0.5944**	**1.0000**	**0.4326**
Hydrogen	0.000000	0.0000	0.000000	0.0000	0.001000	0.0004
Carbon Monoxide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Dioxide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.000000	0.0000	0.000000	0.0000	0.340000	0.1471
Acetylene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethylene	0.005000	0.0005	0.000000	0.0000	0.659000	0.2851
Ethane	0.989600	0.0957	0.000000	0.0000	0.000000	0.0000
Methyl Acetylene/Propadiene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propylene	0.004900	0.0005	0.980000	0.5825	0.000000	0.0000
Propane	0.000500	0.0000	0.020000	0.0119	0.000000	0.0000
Butadienes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butylenes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Butanes	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C5's	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C6-C8 Non-Aromatics	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Toluene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Xylene/ Ethyl Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Styrene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
C9 - 204 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
204 - 288 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
288 C+	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Water	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Nitrogen	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
DMS/DMDS	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.0967		0.5944		0.4326

Column Totals, EPN CR-15

Carbon Monoxide		0.0000		0.0000		0.0000
Carbon Dioxide		0.0000		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000		0.0000
Methane		0.0000		0.0000		0.1471
Ethane		0.0957		0.0000		0.0000
Hydrogen, Water and Nitrogen		0.0000		0.0000		0.0004
Ammonia		0.0000		0.0000		0.0000
Total VOC		0.0010		0.5944		0.2851
Totals		0.0967		0.5944		0.4326

Ethylene Plant Fugitive Emission Totals

CR C3+ Area Fugitives, CR-16

Constituents	Hydrogen Off-Gas (Comp N): Hydrogen Compressor Nos. 1 and 2; Hydrogen PSA		PSA Off-Gas (Comp U): Hydrogen PSA Off-Gas Blend		De-Butanizer Overhead (Comp Y): De-Butanizer Overhead		De-Butanizer Bottoms (Comp W): De-Butanizer Bottoms; Decommissioning - Liquid Service		Hydro C3-4 (Comp Z): Hydrogenation Reactor - Liquid Service		Hydro C3-4 Vapor (Comp AA): Hydrogenation Reactor - Vapor Service	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	0.2978	1.0000	0.0359	1.0000	0.0618	1.0000	0.0556	1.0000	0.0240	1.0000	0.1014
Hydrogen	0.842500	0.2509	0.616300	0.0221	0.000000	0.0000	0.000000	0.0000	0.007500	0.0002	0.419200	0.0425
Carbon Monoxide	0.002500	0.0007	0.006000	0.0002	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Carbon Dioxide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Methane	0.152600	0.0454	0.371900	0.0134	0.000000	0.0000	0.000000	0.0000	0.000100	0.0000	0.000800	0.0001
Acetylene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethylene	0.002300	0.0007	0.005600	0.0002	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ethane	0.000100	0.0000	0.000200	0.0000	0.000200	0.0000	0.000000	0.0000	0.000200	0.0000	0.000400	0.0000
Methyl Acetylene/Propadiene	0.000000	0.0000	0.000000	0.0000	0.018400	0.0011	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propylene	0.000000	0.0000	0.000000	0.0000	0.377700	0.0233	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Propane	0.000000	0.0000	0.000000	0.0000	0.103000	0.0064	0.000000	0.0000	0.484700	0.0116	0.429900	0.0436
Butadienes	0.000000	0.0000	0.000000	0.0000	0.371900	0.0230	0.000400	0.0000	0.000000	0.0000	0.000000	0.0000
Butylenes	0.000000	0.0000	0.000000	0.0000	0.050100	0.0031	0.000100	0.0000	0.000000	0.0000	0.000000	0.0000
Butanes	0.000000	0.0000	0.000000	0.0000	0.058700	0.0036	0.000100	0.0000	0.486900	0.0117	0.147500	0.0150
C5's	0.000000	0.0000	0.000000	0.0000	0.019100	0.0012	0.235800	0.0131	0.019700	0.0005	0.002200	0.0002
C6-C8 Non-Aromatics	0.000000	0.0000	0.000000	0.0000	0.000400	0.0000	0.243600	0.0136	0.000400	0.0000	0.000000	0.0000
Benzene	0.000000	0.0000	0.000000	0.0000	0.000500	0.0000	0.431300	0.0240	0.000500	0.0000	0.000000	0.0000
Toluene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.057400	0.0032	0.000000	0.0000	0.000000	0.0000
Xylene/ Ethyl Benzene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.005500	0.0003	0.000000	0.0000	0.000000	0.0000
Styrene	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.010000	0.0006	0.000000	0.0000	0.000000	0.0000
C9 - 204 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.014600	0.0008	0.000000	0.0000	0.000000	0.0000
204 - 288 C	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.001200	0.0001	0.000000	0.0000	0.000000	0.0000
288 C+	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Water	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Nitrogen	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
DMS/DMDS	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000	0.000000	0.0000
Total		0.2978		0.0359		0.0618		0.0556		0.0240		0.1014

Column Totals, EPN CR-16

Carbon Monoxide		0.0007		0.0002		0.0000		0.0000		0.0000		0.0000
Carbon Dioxide		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Methane		0.0454		0.0134		0.0000		0.0000		0.0000		0.0001
Ethane		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Hydrogen, Water and Nitrogen		0.2509		0.0221		0.0000		0.0000		0.0002		0.0425
Ammonia		0.0000		0.0000		0.0000		0.0000		0.0000		0.0000
Total VOC		0.0007		0.0002		0.0617		0.0556		0.0238		0.0588
Totals		0.2978		0.0359		0.0618		0.0556		0.0240		0.1014

Ethylene Plant Fugitive Emission Totals
CR C3+ Area Fugitives, CR-16 (cont'd)

Constituents	Py-Gas Storage Vapor (Comp X): Decommissioning; Spent Caustic and WAO - All Vapor Service		Quench Water (Comp G): Spent NaOH Storage and WAO - Liquid Service	
	Weight Fraction	Emissions (lb/hr)	Weight Fraction	Emissions (lb/hr)
	1.0000	**0.2018**	**1.0000**	**0.0375**
Hydrogen	0.000000	0.0000	0.000000	0.0000
Carbon Monoxide	0.000000	0.0000	0.000000	0.0000
Carbon Dioxide	0.000000	0.0000	0.000000	0.0000
Hydrogen Sulfide	0.000000	0.0000	0.000000	0.0000
Methane	0.000000	0.0000	0.000000	0.0000
Acetylene	0.000000	0.0000	0.000000	0.0000
Ethylene	0.000000	0.0000	0.000100	0.0000
Ethane	0.000000	0.0000	0.000100	0.0000
Methyl Acetylene/Propadiene	0.000000	0.0000	0.000000	0.0000
Propylene	0.000000	0.0000	0.000000	0.0000
Propane	0.000000	0.0000	0.000000	0.0000
Butadienes	0.032900	0.0066	0.000000	0.0000
Butylenes	0.000400	0.0001	0.000000	0.0000
Butanes	0.000300	0.0001	0.000000	0.0000
C5's	0.180900	0.0365	0.000000	0.0000
C6-C8 Non-Aromatics	0.078800	0.0159	0.000000	0.0000
Benzene	0.110000	0.0222	0.000400	0.0000
Toluene	0.008200	0.0017	0.000100	0.0000
Xylene/ Ethyl Benzene	0.000700	0.0001	0.000000	0.0000
Styrene	0.000300	0.0001	0.000000	0.0000
C9 - 204 C	0.000000	0.0000	0.000000	0.0000
204 - 288 C	0.000000	0.0000	0.000000	0.0000
288 C+	0.000000	0.0000	0.000000	0.0000
Water	0.000000	0.0000	0.999300	0.0375
Nitrogen	0.587500	0.1185	0.000000	0.0000
DMS/DMDS	0.000000	0.0000	0.000000	0.0000
Ammonia	0.000000	0.0000	0.000000	0.0000
Total		0.2018		0.0375

Column Totals, EPN CR-16

Carbon Monoxide		0.0000		0.0000
Carbon Dioxide		0.0000		0.0000
Hydrogen Sulfide		0.0000		0.0000
Methane		0.0000		0.0000
Ethane		0.0000		0.0000
Hydrogen, Water and Nitrogen		0.1185		0.0375
Ammonia		0.0000		0.0000
Total VOC		0.0832		0.0000
Totals		0.2018		0.0375

Occidental Chemical Corporation
December 2012

CR Recovery Area Fugitives - Example Fugitive Calculations

EPN CR-15

Binary Refrigeration (Comp AC)

These fugitive components are associated with the Ethylene Plant. Emissions are controllec using the TCEQ's 28MID program with quarterly monitoring of flanges and connectors

Basis:

Emission factors are taken from the TCEQ's fugitive guidance document for average SOCMI speciatior

Area	Component	Component Count	Emission Factor, lb/hr-comp	Efficiency, %	Fugitive Losses, lb/hr	Fugitive Losses, tons/yr
Equipment in VOC Service	VAL - G/V	534	0.0132	97	0.2115	0.9262
	VAL - G/V exempt		0.0132	0		
	VAL - LL	108	0.0089	97	0.0288	0.1263
	VAL - LL exempt		0.0089	0		
	VAL - HL		0.0005	0		
	PS - LL - MS		0.0439	100		
	PS - LL		0.0439	93		
	PS - HL - MS		0.019	100		
	PS - HL		0.019	0		
	FL - G/V quarterly	1,602	0.0039	97	0.1874	0.8210
	FL - G/V annual		0.0039	75		
	FL - G/V weekly		0.0039	30		
	FL - G/V exempt		0.0039	0		
	FL - LL quarterly	324	0.0005	97	0.0049	0.0213
	FL - LL annual		0.0005	75		
	FL - LL weekly		0.0005	30		
	FL - LL exempt		0.0005	0		
	FL - HL		0.00007	30		
	PRV		0.2293	97		
	CS - BS	4	0.5027	100	0.0000	0.0000
	AS - LL/V		0.0439	100		
Total		2,572			0.4326	1.8948

Calculations Methods:

Hourly Emissions = (component count)(emission factor)(efficiency)

Annual Emissions = (component count)(emission factor)(efficiency)(8,760 hr/yr)(ton/2,000 lb)

Legend:

VAL - G/V	Valves in Gas/Vapor Service
VAL - G/V exempt	Valves in Gas/Vapor Service that are Difficult or Unsafe to Monitor
VAL - LL	Valves in Light Liquid Service
VAL - LL exempt	Valves in Light Liquid Service that are Difficult or Unsafe to Monitor
VAL - HL	Valves in Heavy Liquid Service
PS - LL - MS	Pump Seals in Light Liquid Service w/Mechanical Seal and Barrier Fluid
PS - LL	Pump Seals in Light Liquid Service
PS - HL - MS	Pump Seals in Heavy Liquid Service w/Mechanical Seal and Barrier Fluid
PS - HL	Pump Seals in Heavy Liquid Service
FL - G/V quarterly	Flanges/Connectors in Gas/Vapor Service Subject to Quarterly Monitoring
FL - G/V annual	Flanges/Connectors in Gas/Vapor Service Subject to Annual Monitoring
FL - G/V weekly	Flanges/Connectors in Gas/Vapor Service Subject to Weekly Physical Inspection
FL - G/V exempt	Flanges/Connectors in Gas/Vapor Service that are Difficult or Unsafe to Monitor
FL - LL quarterly	Flanges/Connectors in Light Liquid Service Subject to Quarterly Monitoring
FL - LL annual	Flanges/Connectors in Light Liquid Service Subject to Annual Monitoring
FL - LL weekly	Flanges/Connectors in Light Liquid Subject to Weekly Physical Inspection
FL - LL exempt	Flanges/Connectors in Light Liquid Service that are Difficult or Unsafe to Monitor
FL - HL	Flanges/Connectors in Heavy Liquid Service
PRV	Pressure Relief Valves (w/ Rupture Disks, Vented to a Control Device, or Relieves Thermally)
CS - BS	Compressor/Blower Seals with Barrier Seal
AS - LL/V	Agitator Seals in Light Liquid or Vapor Service w/Barrier Fluid

Ethylene Plant Fugitive Emissions Summary
CR Furnace Area Fugitives, CR-13; Column Totals

Constituents, Column Totals for EPN CR-13	Ethane Feed (Comp B)	Saturated C2 (Comp C)	Furnace Outlet (Comp D)	Quench Overhead (Comp E)	Quench Gasoline (Comp F)	Quench Water (Comp G)	Off-Gas to Fuel (Comp V)	Natural Gas (Comp AD)	Dimethyl Sulfide/Di-methyl Disulfide (Comp AE)	Dimethyl Sulfide/Di-methyl Disulfide Vapor (Comp AF)	Wash Oil (Comp AG)	Wash Oil Vapor (Comp AG)	Ammonia (Comp XX)	EPN CR-13 Total	
	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (tons/yr)
Carbon Monoxide	0.0000	0.0000	0.0003	0.0000	0.0000	0.0000	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0025	0.0107
Carbon Dioxide	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0018	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020	0.0086
Hydrogen Sulfide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Methane	0.0020	0.0031	0.0195	0.0012	0.0000	0.0000	0.1392	0.1437	0.0000	0.0000	0.0000	0.0000	0.0000	0.3086	1.3518
Ethane	0.0744	0.1292	0.0580	0.0036	0.0000	0.0000	0.0001	0.0049	0.0000	0.0000	0.0000	0.0000	0.0000	0.2702	1.1834
Hydrogen, Water and Nitrogen	0.0000	0.0677	0.1820	0.0068	0.0000	0.1260	0.6519	0.0003	0.0000	0.0133	0.0000	0.0409	0.0000	1.0890	4.7697
Ammonia	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0642	0.0642	0.2813
Total VOC	0.0020	0.0039	0.0986	0.0062	0.0336	0.0001	0.0019	0.0014	0.0177	0.0237	0.0177	0.0003	0.0000	0.2069	0.9064
Totals	0.0783	0.2038	0.3586	0.0179	0.0336	0.1261	0.7952	0.1521	0.0177	0.0370	0.0177	0.0412	0.0642	1.9434	8.5119

Ethylene Plant Fugitive Emissions Summary
CR Charge Gas Area Fugitives, CR-14; Column Totals

Constituents	Quench Overhead (Comp E)	Charge Gas Liquid (Comp H)	Quench Water (Comp G)	De-Butanizer Bottoms (Comp W)	Natural Gas (Comp AD)	EPN CR-14 Total	
	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (tons/yr)
Carbon Monoxide	0.0003	0.0000	0.0000	0.0000	0.0000	0.0003	0.0013
Carbon Dioxide	0.0001	0.0000	0.0000	0.0000	0.0010	0.0010	0.0046
Hydrogen Sulfide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
Methane	0.0196	0.0000	0.0000	0.0000	0.0758	0.0955	0.4181
Ethane	0.0583	0.0000	0.0000	0.0000	0.0026	0.0608	0.2664
Hydrogen, Water and Nitrogen	0.1094	0.0282	0.0222	0.0000	0.0002	0.1599	0.7002
Ammonia	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total VOC	0.0992	0.0000	0.0000	0.0780	0.0007	0.1779	0.7793
Totals	0.2868	0.0282	0.0222	0.0780	0.0803	0.4955	2.1701

Ethylene Plant Fugitive Emissions Summary
CR Recovery Area Fugitives, CR-15; Column Totals

Constituents	Quench Overhead (Comp E)	Charge Gas Liquid (Comp H)	Hydrogen Off-Gas (Comp N)	De-Methanizer Feed Vapor (Comp L)	De-Methanizer Liquid Feed (Comp M)	De-Methanizer Overhead Liquids (Comp O)	De-Methanizer Bottoms (Comp P)	AC Reactor Feed (Comp J)	De-Ethanizer Reflux (Comp K)	De-Ethanizer Bottoms (Comp I)	Ethylene Product (Comp Q)	Ethylene Side Reboiler (Comp S)	Ethane Recycle (Comp R)	Propylene Refrigera-tion (Comp AB)	Binary Refrigera-tion (Comp AC)	EPN CR-15 Total	
	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (tons/yr)
Carbon Monoxide	0.0002	0.0000	0.0002	0.0001	0.0000	0.0001	0.0000	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0036
Carbon Dioxide	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0002
Hydrogen Sulfide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
Methane	0.0118	0.0000	0.0113	0.0052	0.0032	0.0560	0.0000	0.0211	0.0004	0.0000	0.0004	0.0000	0.0000	0.0000	0.1471	0.2565	1.1233
Ethane	0.0349	0.0000	0.0000	0.0156	0.0046	0.0001	0.0220	0.0751	0.0137	0.0000	0.0004	0.0112	0.0957	0.0000	0.0000	0.2733	1.1970
Hydrogen, Water and Nitrogen	0.0655	0.0090	0.0623	0.0257	0.0001	0.0001	0.0000	0.1032	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.2665	1.1672
Ammonia	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total VOC	0.0594	0.0000	0.0002	0.0251	0.0145	0.0034	0.0354	0.1125	0.0127	0.0498	0.7771	0.0162	0.0010	0.5944	0.2851	1.9869	8.7028
Totals	0.1718	0.0090	0.0739	0.0717	0.0225	0.0598	0.0575	0.3122	0.0268	0.0498	0.7779	0.0274	0.0967	0.5944	0.4326	2.7841	12.1944

Ethylene Plant Fugitive Emissions Summary
CR C3+ Area Fugitives, CR-16; Column Totals

Constituents	Hydrogen Off-Gas (Comp N)	PSA Off-Gas (Comp U)	De-Butanizer Overhead (Comp Y)	De-Butanizer Bottoms (Comp W)	Hydro C3-4 (Comp Z)	Hydro C3-4 Vapor (Comp AA)	Py-Gas Storage Vapor (Comp X)	Quench Water (Comp G)	EPN CR-16 Total	
	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (tons/yr)
Carbon Monoxide	0.0007	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0010	0.0042
Carbon Dioxide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Methane	0.0454	0.0134	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0589	0.2579
Ethane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0004
Hydrogen, Water and Nitrogen	0.2509	0.0221	0.0000	0.0000	0.0002	0.0425	0.1185	0.0375	0.4717	2.0660
Ammonia	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total VOC	0.0007	0.0002	0.0617	0.0556	0.0238	0.0588	0.0832	0.0000	0.2841	1.2443
Totals	0.2978	0.0359	0.0618	0.0556	0.0240	0.1014	0.2018	0.0375	0.8157	3.5729

Cogeneration Units - Proposed GHG Increased Emissions

EPN's CG-1 and CG-2

(Authorized by Permit Nos. 35335 and PSD-TX-880)

Basis:

215 MM Btu/hr, maximum, total fuel firing rate to provide steam and electrical power for the new NGL facilities
116.91 lb/MM Btu, CO2 factor for natural gas from 40 CFR 98, Subpart C, Table C-1 (converted from 53.02 kg/MM Btu for use with Eq. C-1b)
0.002 lb/MM Btu, CH4 factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.001 kg/MM Btu for use with Eq. C-8b)
0.0002 lb/MM Btu, N2O factor for natural gas from 40 CFR 98, Subpart C, Table C-2 (converted from 0.0001 kg/MM Btu for use with Eq. C-8b)
8,760 hr/yr, hours of operation
Emission calculations below represent maximum emissions for both of the cogeneration units and assume worst-case fuel firing in the heat recover steam generators rather than in the higher efficiency gas turbines

Pollutant	Emission Factor (lb/MM Btu)	Hourly Emissions (lb/hr)	Annual Emissions (tons/yr)
CO_2	116.91	25,135.46	110,093.30
CH_4	0.002	0.47	2.08
N_2O	0.0002	0.05	0.21

Calculation methods:

Hourly emissions (lb/hr) = emission factor (lb/MM Btu) x fuel firing rate (MM Btu/hr)
Annual emissions (tons/yr) = hourly emissions (lb/hr) x hours of operation (hr/yr) x 1 ton/2,000 lb

APPENDIX D
BEST AVAILABLE CONTROL TECHNOLOGY

BEST AVAILABLE CONTROL TECHNOLOGY

New major stationary sources and major modifications must apply best available control technology for each regulated NSR pollutant subject to PSD review. The review of BACT using the EPA's five-step, top-down BACT approach typically includes the following items for each source category: 1) the identification of available control technologies; 2) the elimination of the technically infeasible alternatives; 3) the ranking of the remaining control technologies; 4) the evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects; and 5) the selection of BACT.

For the sources associated with the proposed Ethylene Plant, this BACT review is applied to the five cracking furnaces, two thermal oxidizers, a high pressure ground flare, an emergency generator engine, a low pressure enclosed flare, a cooling tower, a C3/C4 hydrogenation regenerator vent and fugitive sources identified for four operating areas.

It should be noted that the existing cogeneration units are not subject to BACT since they are not modified sources. The cogeneration units are included in this application only because they are affected facilities that influence PSD applicability.

EPN's CR-1 through CR-5; Ethane Cracking Furnaces Nos. 1 through 5

1) The identification of available control technologies. Potential GHG emission control technologies for the cracking furnaces were identified as the follows:

    a) Low carbon fuels – Use of low carbon fuels to reduce the amount of carbon dioxide generated in the combustion process.

    b) Furnace excess air control – Monitoring of oxygen in the flue gas for optimal efficiency.

    c) Good operating and maintenance practices – Visual monitoring of flame patterns and periodic cleaning of burner and feed nozzles to assure complete combustion and efficiency. Also includes periodic refractory repair and cleaning of process heating and waste heat recovery systems when required to maximize thermal efficiency.

    d) Energy efficient design – Use of waste heat recovery from the furnace flue gas and the furnace process effluent gases, thereby offsetting GHG emissions from other process heating sources.

    e) Carbon dioxide capture and storage – Capture, compression, transport and geological storage of carbon dioxide in the cracking furnace flue gas exhaust.

2) The elimination of the technically infeasible alternatives. All options identified in Step 1 are considered technically feasible. The use of low carbon fuels, stack gas oxygen monitors, good operating and maintenance practices and waste heat recovery are all practiced on other process furnaces and have been included into the design of the proposed cracking furnaces. Carbon capture and sequestration (CCS) of the flue gas from the cracking furnaces is considered technically feasible, but not demonstrated commercially on a similar combustion system.

3) The ranking of the remaining control technologies. Carbon dioxide emissions from the cracking furnaces could theoretically be completely absorbed in a conventional amine solvent. The carbon dioxide could then be concentrated in an amine regenerator vent stream, dried, compressed and routed to oil production facilities using carbon dioxide for enhanced oil recovery. The nearest location for this would be in Hastings, Texas which is located about 180 miles away. This would reduce GHG emissions from the cracking furnaces by 312,000 tons per year, and would be the most effective treatment for this individual source.

   Waste heat recovery can reduce GHG emissions from both the furnace and the cogeneration unit by reducing the furnace firing rate and steam demand for the ethylene unit. This requires the installation of heat recovery exchangers on the process outlet gas and the flue gas from the cracking furnace, It is estimated that GHG emissions from the cracking furnaces will be reduced by 43,000 tons per year and GHG emissions from the cogeneration facility will be reduced by about 316,000 tons per year as a result of installing waste heat recovery on the cracking furnaces. This is considered the next most effective control technology.

   The use of the hydrogen rich vent gas from the ethylene recovery section instead of natural gas for fuel in the cracking furnaces reduces amount of carbon dioxide generated in the cracking furnaces. It is estimated that the carbon dioxide emissions from the cracking furnaces is reduced by about 260 tons per year using this alternative low carbon fuel source. This is considered the next most effective control technology for this application.

   Excess air control using stack gas oxygen monitors and good operating and maintenance practices are considered good engineering practice and have been included with the proposed furnace design. Evaluating their effectiveness and a subsequent evaluation of each technology is difficult to quantify and they are considered the least effective.

4) The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects. The capture, compression and sequestration of the carbon dioxide in the cracking furnace flue gas would reduce the GHG emissions from the cracking furnaces by up to 312,000 tons per year, but would require an additional 445 MMBtu/hr of thermal energy to strip the carbon dioxide from the capture solvent. This would require new natural

gas fired steam boilers that would create additional GHG emissions. It is estimated that the increased GHG emissions from the new steam generators would be 280,000 ton/yr.

Consequently, the net overall reduction in GHG emissions would be 32,000 tons/year. The additional capital cost of the recovery and compression equipment and the pipeline is estimated to be about $400,000,000. The cost effectiveness of this technology is reduced by the low carbon dioxide concentrations in the flue gas which is normally only 4.2%.

Significant potential corrosion issues and material selection requirements would also be created by acid gases in the flue gas. The estimated capital cost alone represents about $12,500 per ton of GHG. These costs would exceed values that would make the overall project economically viable. Therefore, this option is rejected as a control option for GHG emissions on the basis of excessive cost.

The use of heat exchangers on the process and flue gas outlet of the cracking furnaces to recover waste heat is estimated to require an additional investment of $50,000,000 and save approximately $17,000,000 annually in fuel costs, while reducing GHG emissions by 359,000 tons per year. The investment cost is about $140 per annual ton of GHG. While these costs are considered excessive for GHG emission controls, when combined with the reduced energy costs this option is considered BACT for this project and is included in the proposed design.

The use of the hydrogen rich vent gas for furnace fuel is considered the most economical use of this vent gas for this site and has been included in the base design. Similarly, good operating and maintenance practices and stack gas oxygen monitors for controlling furnace excess air are considered good engineering practice and have been included with the proposed design. Evaluating their effectiveness and a subsequent evaluation of each technology was not considered necessary for the BACT determination.

5) The selection of BACT. BACT for this application will include the following: the use of low carbon fuel; good operating and maintenance practices; stack gas oxygen monitors for controlling excess air; waste heat recovery from the cracking furnaces in the form of heat exchangers on the furnace process outlets; and boiler feed water economizers in the furnace stacks. Oxygen analyzers will be provided in the stacks. The stack gas temperatures will be maintained at less than 400°F during normal operation and heat exchangers on the process outlet of the furnaces will be installed to reduce the outlet gas temperatures to 850°F or less.

EPN's CR-1-MSS through CR-5-MSS; Ethane Cracking Furnaces Nos. 1 through 5 - MSS Activities

Carbon deposits or coke gradually build up on the tube walls of the furnaces. This coke interferes with heat transfer through the tubes, increasing furnace temperatures and reducing efficiency. The furnace deposits must periodically be removed or decoked. This decoking is accomplished with the introduction of steam and air at high temperatures to convert the deposits to gaseous carbon dioxide. The exhaust gas is discharged through the furnace with the flue gas. The carbon dioxide from decoking is included in the emissions from the cracking furnaces. This section will address the carbon dioxide that is generated from removing the coke deposits.

1) The identification of available control technologies. Potential GHG emission control technologies for the cracking furnaces were identified as the follows:

    a) Mechanical cleaning – Use shot blast or hydro-lancing to mechanically remove coke from the tubes. The coke would then be disposed of in a solid waste landfill.

    b) Reduced air – Limit the air feed to reduce carbon dioxide formation.

    c) Low coking design and operation – Proper furnace design and operation will tend to reduce coke formation and minimize carbon dioxide formation.

2) The elimination of the technically infeasible alternatives. All of the identified alternatives are technically feasible.

3) The ranking of the remaining control technologies. Physical removal of the coke would provide the most effective control of carbon dioxide emissions. It is estimated that up to 640 tons/yr of carbon dioxide production could be eliminated. Reducing the air would result in some of the carbon being converted to carbon monoxide instead of carbon dioxide. It is estimated that potentially as much as 50% of the carbon could be converted to carbon monoxide instead of carbon dioxide which would reduce carbon dioxide emissions by 320 tons per year. Low coking design and operation is difficult to quantify, but is considered the least effective means of control. Assuming run life is extended by 25%, the reduction in carbon dioxide emissions is equivalent to about 160 tons per year.

4) The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects. The cracking furnaces have vertical tube coils of varying diameters. Mechanical cleaning of the coils would require the cutting and physical removal of the furnace coils and bends during each decoke. The coils would then have to be re-welded after cleaning. The costs and potential safety issues with the re-welding of materials are excessive for the minimal reduction in GHG emissions. The operation would also generate additional PM emissions from the decoking. Mechanical cleaning is rejected as a control option for GHG emissions from decoking.

    Limiting the air feed would increase carbon monoxide while reducing carbon dioxide. Carbon monoxide is a criteria pollutant with higher toxicity than GHG, so this alternative is rejected as a control option for GHG emissions.

Minimizing coke formation through the proper furnace coil design for the feedstock and the use of anti-coking agents will increase furnace run time between decoking and improve furnace efficiency, thereby reducing operating costs. These design features are included in the proposed furnace design.

5) The selection of BACT. The use of a proper furnace coil design for ethane together with the use of anti-coking agents in the furnace feed to maximize the furnace run time between decokes is commonly practiced and considered BACT for this application. The total number of furnace decokes is expected to be 36 per year.

EPN's CR-6 and CR-7; CR Thermal Oxidizer Nos. 1 and 2

1) The identification of available control technologies. Non-condensable vent streams from the ethane cracking process, storage and loading area are generally combusted to destroy VOC before the inert gases are released to the atmosphere. This control can be accomplished in elevated flares, enclosed flares and vapor combustors (thermal oxidizers). The destruction efficiency and the potential GHG control technologies will vary depending on the type of combustion device that is selected.

   Since elevated flares and enclosed flares offer no opportunity for heat recovery and increased energy efficiency (i.e., minimizing GHG emissions by using waste heat to create steam, and thereby, lessening fuel firing in other steam generating sources), the primary control technologies for the destruction of waste gas streams focus on the use of thermal oxidizers. Potential GHG emission control technologies for VOC thermal oxidizers are identified as follows:

   a) Combustor design – Design achieves good fuel and air mixing with sufficient temperatures to assure complete combustion and to maximize thermal efficiency.

   b) Oxidizer air/fuel control – Monitoring of oxygen in the flue gas and firebox temperature for optimal efficiency.

   c) Flame monitoring and periodic tune-up – Visual monitoring of flame patterns and periodically cleaning of burner and feed nozzles to assure complete combustion and efficiency. Also, includes periodic refractory repair and cleaning of waste heat recovery systems when required to maximize thermal efficiency.

   d) Waste heat recovery – Use of thermal oxidizers with high firebox temperatures and waste heat recovery from the oxidizer exhaust to preheat the combustion air or produce steam for use at the site, thereby offsetting GHG emissions from other fuel combustion sources.

   e) Combustion CO_2 capture and storage – Capture, compression, transport and geological storage or use of CO_2 in the thermal oxidizer flue gas exhaust.

2) The elimination of the technically infeasible alternatives. All options identified above are considered technically feasible. Periodic tune-ups, high combustor design efficiency, oxidizer air/fuel control and waste heat recovery are all practiced at other thermal oxidizers operated at the site and have been included into the design of the proposed thermal oxidizers. Compression, transport and storage of the CO_2 rich amine regenerator vent streams are also practiced at some sites. Carbon capture and sequestration (CCS) of the vent gas from the thermal oxidizer is considered technically feasible, but not demonstrated commercially on a similar, small combustion system.

3) The ranking of the remaining control technologies. CO_2 emissions from the thermal oxidizer flue gas could theoretically be completely absorbed in a conventional amine solvent. The CO_2 could then be concentrated in an amine regenerator vent stream, compressed and routed to oil production facilities using CO_2 for enhanced oil recovery. The nearest location for this enhanced oil recovery would be in Hastings, Texas which is located about 180 miles away. This CO_2 recovery would reduce GHG emissions from the thermal oxidizers by 111,700 tons/yr and would be the most effective treatment for this individual source.

   Waste heat recovery can reduce GHG emissions from the cogeneration units by reducing steam demand for the Ethylene Plant. This approach requires the use of an enclosed combustion system such as a thermal oxidizer, instead of a less expensive elevated flare. It is estimated that GHG emissions from the cogeneration facilities will be reduced by about 18,200 tons/yr as a result of installing waste heat recovery on thermal oxidizers. This reduction is based on the more efficient cogeneration operation of raising gas turbine loads to maintain power output. This approach is considered the next most effective control technology.

   Combustor design, oxidizer air/fuel with temperature control, stack gas oxygen monitors and flame monitoring are considered good engineering practice and have been included with the proposed design. Evaluating their effectiveness and a subsequent evaluation of each technology is difficult to quantify, but they are considered the least effective.

4) The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects. The capture, compression and sequestration of the CO_2 in the thermal oxidizer flue gas would reduce the GHG emissions from the thermal oxidizers by 111,700 tons/yr, but would require an additional 159 MM Btu/hr of thermal energy to strip the CO_2 from the solvent. This approach would require new natural gas-fired steam boilers that would create additional GHG emissions. It is estimated that the increased GHG emissions from the new steam generators would be 100,300 tons/yr.

   Consequently, the net overall reduction in GHG emissions would be 11,400 tons/yr. The additional capital cost of the recovery and compression equipment and the pipeline is estimated to be about \$350,000,000. Significant potential corrosion issues and material selection requirements would be created by the sulfur dioxide in the flue gas. The capital cost represents about \$30,700 per ton of GHG, and the additional operating costs in terms of fuel alone would be \$4,000,000 per year. These costs would exceed values that would make the overall project economically viable. Therefore, this option is rejected as a control option for GHG emissions on the basis of excessive cost.

The use of thermal oxidizers with waste heat recovery is estimated to require an additional investment of \$5,500,000 and will save approximately \$800,000 annually in fuel costs, while reducing GHG emissions by 18,200 tons/yr. The investment cost is about \$300 per annual ton of GHG. While these costs are considered excessive for GHG emission controls, when combined with the reduced energy costs, this option is considered BACT for this project and is included in the proposed design.

Combustor design, oxidizer air/fuel with temperature control, stack gas oxygen monitors and flame monitoring are considered good engineering practice and have been included with the proposed design. Evaluating their effectiveness and a subsequent evaluation of each technology was not considered necessary for this BACT determination.

5) The selection of BACT. High oxidizer design efficiency, oxidizer air/fuel control and flame monitoring are all currently practiced on other thermal oxidizers operating on the site to maximize efficiency and are considered BACT for this application. The firebox temperature will be monitored and maintained at a temperature of 1,300 °F or more to assure complete combustion and improve energy recovery.

   An oxygen analyzer in each stack will be provided to assure there is sufficient air. Vent gas feed, supplemental natural gas fuel and combustion air flow will be metered into each thermal oxidizer. The firebox will be lined with refractory to minimize heat losses to the atmosphere.

   It is proposed that waste heat recovery in the form of steam generation also be included due to the energy savings and the reduction in GHG emissions.

EPN CR-8; CR High Pressure Flare

1) The identification of available control technologies. The high pressure flare is used to safely dispose of large volumes of non-condensable flammable hydrocarbon vapor streams during start-up and shutdown, emergency conditions and decommissioning of large volumes of hydrocarbons for maintenance. Under normal operation, the only GHG emissions associated with the flare are from the natural gas pilot burners.

The only viable control technologies for reducing GHG emissions from the flare are minimizing the size and number of the pilots. Potential GHG emission control technologies for the emergency flare are identified as follows:

a) Pilot reliability and sizing – The use of energy efficient pilots to minimize natural gas consumption.

b) Pilot flame monitoring and periodic cleaning – Monitoring of the pilots with temperature monitors and periodically cleaning of burner to assure proper combustion and efficiency.

2) The elimination of the technically infeasible alternatives. All options identified above are considered technically feasible.

3) The ranking of the remaining control technologies. Modern high efficiency pilots can reduce natural gas consumption by about 30% over larger traditional pilots. This approach will reduce GHG emissions by about 253 tons/yr. This option is considered the most effective technology.

   Pilot flame monitoring is considered good engineering practice and has been included with the proposed design.

4) The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects. High efficiency pilots reduce natural gas consumption as well as GHG emissions and do not cost more than larger traditional pilots. Therefore, they are included in the proposed design. Pilot flame monitoring is considered good engineering practice for safety as well as environmental compliance and has been included with the proposed design.

5) The selection of BACT. The use of high efficiency pilots with pilot flame monitoring will be included for safety and performance. Total pilot duty for all stages will be minimized.

   Each pilot will be monitored with a thermocouple. Both electronic and flame front generator systems will be provided for lighting the pilots.

EPN CR-8-MSS; CR High Pressure Flare - MSS Activities

1) The identification of available control technologies. The high pressure flare is used to safely dispose of large volumes of non-condensable flammable hydrocarbon vapor streams during start-up and shutdown, emergency conditions and decommissioning of equipment for maintenance.

   Potential GHG emission control technologies for the emergency flare are identified as follows:

a) Staged flare design – the installation of a staged flare design with good combustion practices to minimize assist gas during low load operation will reduce GHG emissions from the flare when in operation.

b) Low carbon assist gas – The use of a low carbon fuel for assist gas will reduce GHG emissions from the flare when assist gas is required at low loads.

c) Waste heat recovery – Use of thermal oxidizers with waste heat recovery from the oxidizer exhaust to preheat the combustion air or produce steam for use at the site, thereby offsetting GHG emissions from other fuel combustion sources.

d) Combustion CO_2 capture and storage – Capture, compression, transport and geological storage or use of CO_2 in the thermal oxidizer flue gas exhaust.

2) The elimination of the technically infeasible alternatives. Thermal oxidizers with waste heat recovery and CO_2 capture and storage would require an enclosed combustion system. This is not technically feasible for safety reasons due to the potential for instantaneous high flow from the emergency relief system. Staged flare design and flare gas feed controls are technically feasible.

3) The ranking of the remaining control technologies. A staged flare design minimizes the use of supplemental assist gas required for complete combustion over a large operating range for the flare. The use of a low carbon assist gas such as natural gas will further reduce the GHG emissions when assist gas is required at very low loads. This approach is considered the next most effective technology for GHG emission control for this application.

4) The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects. In addition to the reduction in GHG emissions, a staged flare with good combustion practices provides the most reliable and effective control of VOC emissions with the least amount of supplemental assist fuel, which also minimizes cost. Natural gas is also considered the most reliable and economical assist gas. Both of these options have been included in the proposed design.

5) The selection of BACT. The use of a staged flare with a high turndown, along with good combustion practices, and the use of low carbon natural gas as an assist gas are considered BACT for this application.

EPN's CR-9; CR Emergency Generator Diesel Engine

1) The identification of available control technologies. The diesel-fired emergency generator

engine is included in this application for the Ethylene Plant because of GHG emissions that occur during the scheduled testing of the engine. Use of this engine for emergency conditions will not be authorized by this permit since these emergency events are not subject to permitting requirements.

A natural gas-fired and electrically driven engine is also a possibility to consider; however, its availability during emergency events is not as certain as a diesel-fired engine, and so, it is not considered as practical technology for this service.

Potential GHG emission control technologies for this engine are identified as follows:

a) EPA Tier 2 level of emission limitations for combustion products.

b) Change oil and filter every 500 hours of operation or annually, whichever comes first.

c) Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first.

d) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

2) The elimination of the technically infeasible alternatives. All options identified above are considered technically feasible.

3) The ranking of the remaining control technologies. The ranking of the MACT, Subpart ZZZZ, Table 2d requirements for emergency diesel engines mentioned above are difficult to determine relative to effectiveness of emissions control, but all are expected to be relevant for maintaining clean operations.

4) The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects. Again, the effectiveness of controls, energy impacts, and environmental effects for a diesel engine that is operated only a few hours a year is difficult to ascertain.

5) The selection of BACT. Due to the negligible amount of costs associated with the control techniques mentioned above and the positive effect of their implementation, all of the proposed efforts are considered as appropriate measures of BACT and will be utilized.

EPN CR-10; CR Low Pressure Flare

1) The identification of available control technologies. The low pressure flare is used as a back-up device to the thermal oxidizers. It is used only during periods when the thermal oxidizers are unavailable to process the vent gases from the Ethylene Plant, storage and

loading area. Under normal operation, the only GHG emissions associated with the flare are from the natural gas pilot burners. Potential GHG emission control technologies for the flare pilots are identified as follows:

a) Low carbon fuel – Use of a low carbon fuel for the pilots will reduce GHG emissions.

b) Pilot reliability and sizing – The use of energy efficient pilots to minimize natural gas consumption.

c) Pilot flame monitoring and periodic cleaning – Monitoring of the pilots with temperature monitors and periodically cleaning of burner to assure proper combustion and efficiency.

d) Combustion CO_2 capture and storage – Capture, compression, transport and geological storage or use of CO_2 in the thermal oxidizer flue gas exhaust.

2) The elimination of the technically infeasible alternatives. CO_2 capture and storage for a flare is not technically feasible because the flare is not an enclosed combustion system. All other options identified above are considered technically feasible.

3) The ranking of the remaining control technologies. Modern high efficiency pilots can reduce natural gas consumption by about 30% over larger traditional pilots. This approach will reduce GHG emissions by about 100 tons/yr and is considered the most effective technology.

   The use of a low carbon fuel such as natural instead of a liquefied petroleum gas will reduce GHG emissions by about 3 tons per year. This option is considered the next most effective control technology.

   Pilot flame monitoring is considered good engineering practice and has been included with the proposed design.

4) The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects. High efficiency pilots reduce natural gas consumption as well as GHG emissions and do not cost more than larger traditional pilots. Natural gas is considered the most economical and reliable source of fuel for the pilots and is included in the proposed design. Both of these features are included in the proposed design. Pilot flame monitoring is considered good engineering practice for safety as well as environmental compliance and has been included with the proposed design.

5) The selection of BACT. The use of high efficiency natural gas pilots, with pilot flame monitoring, is selected as BACT for this application to minimize pilot duty. Each pilot will be monitored with a thermocouple. Both electronic and flame front generator systems will be provided for lighting the pilots.

EPN CR-10-MSS; CR Low Pressure Flare - MSS Activities

1) The identification of available control technologies. The low pressure flare is used as a back-up device to the thermal oxidizers. It is used only during periods when the thermal oxidizers are unavailable to process the vent gases from the Ethylene Plant, storage and loading area. These events are expected to occur during plant shutdowns when the boiler feed water and steam systems must be taken out of service for maintenance and inspection. Potential control technologies for GHG emissions include:

    a) Redundant thermal oxidizers – The installation of redundant thermal oxidizers minimizes the probability of flaring due to an unexpected shutdown of a single thermal oxidizer.

    b) Flare gas feed controls – The installation of flare gas feed meters and temperature monitors in the flare to minimize supplemental natural gas requirements when in operation.

2) The elimination of the technically infeasible alternatives. All options identified above are considered technically feasible.

3) The ranking of the remaining control technologies. Thermal oxidizers require periodic maintenance for refractory repair, fan and motor bearing maintenance, burner inspection and repair and waste heat boiler inspection and cleaning. Typically, at least two weeks/yr are required for inspection and maintenance. By retaining the waste heat recovery with a second unit during this two week period and avoiding flaring, it is estimated that GHG emissions will be reduced by about 700 tons/yr. This approach is considered the most effective control technology.

    Flare gas feed controls are only effective when the flare is in service. Since this control will only occur during emergency circumstances, it is considered the least effective control technology for this specific system.

4) The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects. In addition to the reduction in GHG emissions and improved energy recovery, a second thermal oxidizer reduces unit downtime and provides improved reliability and effectiveness in maintaining a high destruction efficiency of VOC and sulfur bearing compounds. The total installed cost of a second unit is expected to be about $6,000,000. While this cost is considered excessive for GHG emission control, the overall improvement in reliability, efficiency and environmental compliance justifies the installation of a second unit and it is included in the proposed design.

    Flare gas feed controls are also considered good engineering practice for safety as well as environmental compliance and have been included with the proposed design.

5) The selection of BACT. The use of redundant thermal oxidizers is currently practiced on the site for other processes and is considered BACT for this application. Feed flow meters and temperature monitors inside the enclosed flare will provide rapid indication when the unit is operating. Natural gas will be automatically added to the feed to assure adequate heating values for effective combustion.

EPN CR-11; CR Cooling Tower

1) The identification of available control technologies. The cooling requirements for the Ethylene Plant are generally provided by evaporative cooling systems, but can also be provided by once through sea water cooling or air cooling. The make-up water can also be pre-treated for removal of the bicarbonates.

   Potential GHG emission control technologies for the cooling system are identified as follows:

   a) Low cycles of concentration – The tower could be operated at sufficiently low cycles of concentration so as to not require any acid addition.

   b) Acid and blowdown control – Monitoring of circulating water pH and conductivity to control the acid addition and blowdown to control water chemistry.

   c) Pretreatment of make-up water – Use a reverse osmosis system to remove bicarbonates in the make-up water.

   d) Once through seawater cooling – Use of once through seawater for process cooling rather than an evaporative cooling system.

   e) Air cooling – Use of air coolers rather than an evaporative cooling water system for process cooling.

2) The elimination of the technically infeasible alternatives. All options identified above are considered technically feasible.

3) The ranking of the remaining control technologies. The use of once through seawater cooling would eliminate the 668 tons per year of CO_2 emissions from the cooling tower with minimal increase in power or thermal combustion related GHG emissions. This approach is considered the most effective control for GHG emissions.

   The use of air cooling would also eliminate the 668 tons per year of CO_2 emissions from the cooling tower; however, it would significantly increase the power and thermal energy requirements for the Ethylene Plant. These greater power and energy requirements are due to higher operating temperature and pressure in the refrigeration and distillation column condensers. This approach would result in increased GHG emissions from the cogeneration facilities; however, this approach is considered the next most effective control for GHG emissions from the plant's cooling system.

Pretreatment of the make-up water in a reverse osmosis system could remove most of the bicarbonates from the cooling tower make-up and potentially eliminate the CO_2 emissions from the cooling tower. This pretreatment would result in increased GHG emissions from the cogeneration facilities for the additional power requirements for the reverse osmosis systems, which require high water pressure to operate effectively.

Operation of the cooling tower with a very heavy wastewater blowdown to reduce the bicarbonate concentration could reduce the CO_2 emissions by 80-90%. There is still some dissolved CO_2 in the make-up water that would be stripped out even if no acid were added. This approach is considered the next most effective control technology.

The effect on GHG emissions of using pH and specific conductivity monitoring to control the acid injection and blowdown is difficult to assess, but it is considered the least effective means of control.

4) The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects. The use of once through seawater cooling might be considered detrimental to fish and wildlife. Also, the use of seawater can lead to increased fouling of heat exchangers. Therefore, due to the minimal reduction in GHG emissions, this technology is not chosen as a control option for GHG emissions on the basis of these negative consequences.

   The use of air cooling would eliminate the cooling tower GHG emissions, but increase emissions from the cogeneration facilities. It is difficult to assess, but air cooling for these facilities would generally be expected to increase energy consumption by 5-10%. This approach would represent 8,000 to 16,000 tons per year of increased GHG emissions from the cogeneration facilities. The increased emissions would certainly be significantly more than the 688 tons per year that would be eliminated from the cooling tower. Therefore, air cooling is rejected on the basis of overall energy consumption and the overall increase in GHG emissions.

   Pretreatment of the make-up water in a reverse osmosis system would require increasing the water pressure by several hundred psig. The additional power requirements would add about 4 MM Btu/hr of natural gas firing at the cogeneration facilities, increasing the GHG emissions by 2,048 tons per year. These GHG emissions more than off-sets the elimination of the 668 tons per year of GHG emissions from the cooling tower. Therefore, pretreatment of the make-up water by reverse osmosis is rejected due to the overall increase in GHG emissions.

The blowdown rate from the cooling tower would need to be increased from 300 gallons per minute to at least 800 - 1200 gallons per minute to prevent scaling in the cooling water system without any acid addition. There is no other use for this water and it would have to be discharged as wastewater. This approach is considered extremely wasteful of fresh water, especially considering the minimal reduction in GHG emissions that would be realized, and therefore, this approach is rejected as a reasonable control option.

The use of pH and specific conductance monitoring of the cooling tower water to control acid addition and blowdown rate would be cost prohibitive for GHG emission control due to the minor reduction in GHG emissions. However, if pH and conductivity monitors are implemented to control scaling or corrosion, it will also result in some improved control of GHG emissions by maintaining consistent alkalinity in the cooling tower water. It is proposed that continuous pH and conductivity monitors be included on the cooling tower water.

5) The selection of BACT. Due to the negligible amount of GHG emissions, none of the available control technologies are considered cost effective. However, OxyChem intends to install pH and conductivity analyzers on the cooling water supply to control acid addition and blowdown. Laboratory instruments will be used to periodically check the accuracy of these devices and provide information when the on-line analyzers are out of service for an extended period of time due to maintenance. This approach will minimize the GHG emissions associated with the cooling tower and satisfy GHG BACT requirements.

EPN CR-12; C3/C4 Hydrogenation Reactor Regeneration Vent – MSS Activities

The unsaturated C3's and C4's are hydrogenated to propane and butane over a fixed bed catalyst in the C3/C4 Hydrogenation Reactor. Over time, carbon will deposit over the catalyst surface. Periodically the carbon deposits must be removed to maintain catalyst activity and reactor conversion. This is accomplished with the introduction of high temperature steam and air to convert the carbon deposits to gaseous carbon dioxide. The exhaust gas is discharged to the atmosphere during this operation. Eventually the catalyst can no longer be successfully regenerated and must be replaced.

1) The identification of available control technologies. Potential GHG emission control technologies for the C3/C4 Hydrogenation Reactor Regeneration Vent were identified as the follows:

   a) Catalyst disposal – Dispose of catalyst and replace with new catalyst instead of regenerating the catalyst.

   b) Reduced air – Limit the air feed to reduce carbon dioxide formation.

c) Low coking design and operation – Proper reactor design and operation will tend to reduce coke formation and minimize carbon dioxide formation.

2) The elimination of the technically infeasible alternatives. All of the identified alternatives are technically feasible.

3) The ranking of the remaining control technologies. Disposing of the catalyst by landfill would eliminate this GHG emission source (13 tons per year). This is the most effective control technology for GHG emissions from this source. Reducing the air would result in some of the carbon being converted to carbon monoxide instead of carbon dioxide. It is estimated that potentially as much as 50% of the carbon could be converted to carbon monoxide instead of carbon dioxide which would reduce carbon dioxide emissions by 6.5 tons per year. Low coking design and operation is difficult to quantify, but is considered the least effective means of control. Assuming run life is extended by 25%, the reduction in carbon dioxide emissions is equivalent to about 3 tons per year.

4) The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects. Disposing of the catalyst instead of regeneration would generate additional solid waste and represent a significant cost burden for replacement catalyst. Although the catalyst production methods are not known by OxyChem, it is believed that the additional GHG emissions from the production of the new catalyst would likely exceed those of regeneration, so this technology is not expected to be beneficial from a GHG perspective. Consequently, catalyst disposal is rejected as a control technology.

   Limiting the air feed would increase carbon monoxide while reducing carbon dioxide. Carbon monoxide is a criteria pollutant with higher toxicity than GHG, so this alternative is rejected as a control option for GHG emissions.

   Minimizing coke formation through the proper reactor design and operation will increase reactor run time between regeneration, thereby reducing operating costs. These design features are included in the proposed design.

5) The selection of BACT. A proper reactor design with good operating practices will minimize coke formation and is considered BACT for this application. The reactor will be fed a C3/C4 distillate and a purified hydrogen stream to minimize contaminants and catalyst fouling. The reactor will be loaded with hydrogenation catalyst per catalyst supplier recommendations. Reactor temperatures, pressures and hydrogen concentrations will be maintained within recommended levels.

EPN's CR-13, 14, 17 and 16; Ethylene Plant Fugitive Emissions

1) The identification of available control technologies. Fugitive leakage from process

equipment piping components associated with the proposed project includes methane and CO_2. The controlled emissions associated with these components have been estimated to be less than a ton/yr of both methane and CO_2.

Potential GHG emission control technologies for the fugitive emissions are identified as follows:

a) Barrier sealing systems for pumps and compressors.

b) Installing rupture discs beneath pressure relieving devices discharging to the atmosphere.

c) Use of bellows sealed valves to eliminate valve stem packing leaks.

d) Administration of a leak detection and repair (LDAR) program for fugitive emissions.

2) The elimination of the technically infeasible alternatives. All options identified above are considered technically feasible.

3) The ranking of the remaining control technologies. The use of barrier sealing systems for pumps and compressors, rupture discs for relief devices and bellows sealed valves address separate sources. Each technology is capable of 100% control for each source and each technology is considered the most effective control technology.

LDAR programs are typically used to control VOC emissions and can achieve up to 97% control of VOC emissions. Although not specifically designed for GHG emissions, they can be used to control GHG since VOC is generally present in the same components that would be included in an LDAR program for VOC. It is assumed that the same control factors can be applied to GHG emissions. This approach is considered the least effective control technology.

4) The evaluation of the most effective controls regarding cost-effectiveness, energy impacts and environmental effects. Valves make up one of the largest sources of fugitive emissions and the use of bellows sealed valves can eliminate GHG emissions from the valve stems. These valves are generally only available on rising stem valves such as gate and globe valves. They are also commonly only available in the smaller sizes, and significantly more expensive.

Consequently, their overall effectiveness is limited. The marginal additional level of control that is achieved over an LDAR program is minimal and not considered cost effective for VOC or GHG control.

The installation of rupture discs beneath relief valves, and barrier seals for pumps and compressors to control a negligible amount of GHG fugitive emissions that occur from these sources is considered cost prohibitive. However, if these controls are being implemented for VOC emission control purposes, they will also result in effective control of the small amount of GHG emissions associated with these fugitive emission sources.

The use of an LDAR program to control a negligible amount of GHG emissions that occur as process fugitives is also considered cost prohibitive. However, again, if an LDAR program is being implemented for VOC emission control purposes, it will also result in an effective control of the small amount of GHG emissions associated with the same piping components.

The TCEQ's most aggressive BACT-styled fugitive monitoring and maintenance program, 28MID with quarterly monitoring of flanges, is currently considered BACT for controlling fugitive VOC emissions at the existing site. It is more aggressive than the 28LAER program due to the quarterly flange monitoring. As part of this 28MID approach all pumps and compressor seals in light liquid service are vented to control or are designed with non-leaker technology. It has been proposed that this program be expanded to control VOC emissions from the new Ethylene Plant.

5) The selection of BACT. Due to the negligible amount of fugitive GHG emissions, none of the available control technologies are considered cost effective. However, where technically feasible, OxyChem will install rupture discs beneath relief valves discharging to the atmosphere and will install barrier seal systems on pumps and compressors in VOC services. OxyChem will also implement a TCEQ-styled 28MID LDAR program for VOC control purposes. This program will satisfy GHG BACT requirements.