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

May 18, 2012

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

Re: Federal Prevention of Significant Deterioration Permit Application
Natural Gas Liquids Fractionation Facilities
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. Magee:

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 natural gas liquids fractionation facilities 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) on April 27, 2012. In order to facilitate a better understanding of these parallel permitting processes, you were copied on this TCEQ application.

As discussed in our meeting in September 2011 with you and other EPA staff members regarding this 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 very 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 R. Evans

Mark R. Evans
Environmental Manager

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

NATURAL GAS LIQUIDS (NGL) FRACTIONATION FACILITIES

May 2012

Submitted by:

Mark R. Evans
Environmental Manager
Occidental Chemical Corporation

Prepared by:

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

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INTRODUCTION

Occidental Chemical Corporation (OxyChem) is proposing to construct and operate a new 87,000 barrel per day (BPD) NGL Plant at its existing site near Ingleside, Texas on land immediately adjacent to the existing Vinyl Chloride Monomer (VCM) Plant owned and operated by OxyChem. The new NGL fractionation plant will receive natural gas liquids by pipeline and will fractionate these liquids into commercial grade products (ethane, propane, butanes, and natural gasoline), which will be stored on-site (except for ethane, which will be routed to the pipeline without storage), and then transferred to markets by various means, including pipeline, tank trucks, rail cars, and barges.

It should be noted that these fractionation facilities constitute a major modification and are subject to federal prevention of significant deterioration (PSD) review for the following pollutants: volatile organic compounds, nitrogen oxides, carbon monoxide, 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 an application submitted to the TCEQ on April 27, 2012. 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.

NGL FRACTIONATION FACILITIES' PROCESS DESCRIPTION

Process facilities receive NGL by pipeline and separate these liquids by distillation into four products: ethane, propane, mixed butanes, and natural gasoline (higher molecular weight hydrocarbons in the NGL after ethane, propane and butanes are removed). Distillation concentrates sulfur compounds found in the NGL feed in the mixed butanes and natural gasoline fractions. A dedicated process unit converts these sulfur compounds to disulfide oil to be blended with the natural gasoline.

Each distillation process in the NGL Fractionation Facilities operates under pressure. Each distillation process includes a fractionation column, a reboiler to provide heat for the distillation of liquids, and means to condense the vaporized fraction. Steam, supplied both from an adjacent existing natural gas fired cogeneration unit and from new generation facilities installed with the NGL plant, is supplied to these reboilers. Cooling and condensing for the fractionation columns is supplied from recirculating propane refrigerant and recirculating cooling water, both supplied from new facilities to be installed at the NGL fractionator site.

Carbon dioxide and other acid gases present in the NGL feed are extracted by a recirculating amine stream. Vent gases from regeneration of these amines are routed to a thermal oxidizer for destruction of organic compounds. Water and some aromatic hydrocarbons in the NGL feed are extracted by a recirculating glycol stream. Vent gases from regeneration of the glycol are also routed to a thermal oxidizer for destruction of organic compounds. Small amounts of liquid waste created in the recirculating amine and glycol streams are removed as blowdown. Small amount of solids in these recirculating streams are removed by filters and are discarded as solid wastes along with the filter media.

Sulfur-containing organic compounds present in the NGL feed are concentrated by fractionation into the materials fed to the debutanizer. Sulfur compounds present in the overhead product (mixed butanes) and bottom product (natural gasoline) from the debutanizer are converted to disulfide oils which are blended with the natural gasoline. These conversion/extraction processes create vapor discharges which are routed to the thermal oxidizers and sulfide-rich aqueous caustic streams. These sulfide-rich caustic streams are treated to convert sulfides to disulfides and then regenerated to remove the disulfide oil after which the regenerated caustic stream is recycled to butane and gasoline sulfur-removal units. A small stream of sulfidic caustic will be periodically removed as a liquid waste stream, which will be disposed of off-site in accordance with applicable requirements.

Stored liquid products are transferred to markets by pipeline, by tanker truck, by rail car and by barge. Propane, butane, and natural gasoline products which do not meet specifications are stored temporarily on-site until they can be reprocessed.

Process wastewaters from NGL fractionators and product storage, transfer, and loading facilities are collected and transferred in closed systems to a wastewater storage tank. Collected wastewaters are steam-stripped to remove organic compounds with the overhead vapor routed to the thermal oxidizer. The stripped wastewater is pumped to a biological treatment system at the existing plant. Vapors from process wastewater collection drain tanks, separator vents and the spent caustic oxidizer vent are routed to the thermal oxidizers.

Wastewaters from surface drainage are handled in open systems and pumped into the wastewater storage tank from which the liquid effluent is pumped to the steam stripper before discharge to a biological oxidation system.

A process flow diagram for the new NGL Fractionation Facilities 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 new sources of emissions proposed for the fractionation facilities are identified as follows: two thermal oxidizers, a flare, a cooling tower, fugitive sources identified for five operating areas, an emergency generator engine and four firewater pump engines. GHG emissions are expected from all of these sources except for four of the five 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 fractionation 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 NGL-1 and NGL-2; NGL 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 60 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. Most of the product tanks are pressurized tanks. 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, non-pressurized loading vapors from barge, rail car and truck loading will be handled through the oxidizers. The pressure ratings of the rail cars and trucks are sufficient to maintain 100% collection of displaced vapors. The non-pressurized barge loading operations are also expected to maintain 100% collection of displaced vapors since these transfer operations will include vacuum assist.

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.

The GHG emissions calculated for the thermal oxidizers 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).

EPN NGL-3; NGL Emergency Flare

The emergency 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 upsets (emission events), which are events that are not subject to permitting requirements. The emergency flare is an enclosed flare.

EPN NGL-4; 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's NGL-5; NGL Process Area Fugitives

Fugitive emissions have been estimated as equipment leaks in these five areas of the proposed facilities: the NGL Process Area (EPN NGL-5), the Gasoline Storage Area (EPN NGL-6), the LPG Storage Area (EPN NGL-7), the NGL Barge Loading Area (EPN NGL-8) and the NGL Rail Car and Truck Loading Area (EPN NGL-9). Calculations utilize the TCEQ's SOCMI factors without ethylene and reductions consistent with the use of a TCEQ-styled 28MID fugitive monitoring and maintenance program with quarterly monitoring of flanges.

Most new pumps and compressors will have dual mechanical seals that route vapor losses to a control device or will be of equivalent non-leaker design. Due to this level of control, these pumps and compressors are not identified in the calculations found in Appendix C. Pumps in heavy liquid service are exceptions. Since they are not equipped for fugitives control, they are included in the calculations.

Similarly, 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 routed to the thermal oxidizers for control, so losses through the relief valves are a secondary option for managing these tank losses.

Detailed calculations are only provided for the NGL Process Area Fugitives since that area is the only one that includes GHG emissions. VOC and GHG speciation is provided with the fugitive emission calculations. This speciation includes a reasonable GHG distribution for the NGL feeds expected to be processed at the site.

EPN's NGL-10, 11, 12, 13 and 14; NGL Emergency Generator Diesel Engine and Firewater Pump Diesel Engines

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

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 cogeneration units will enter in the scope of the project to supply the new demand for steam, and possibly 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 310 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 fractionation facilities.

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 NGL Fractionation Facilities is provided as follows:

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
NGL-1	NGL Thermal Oxidizer No. 1	41,449.69	33.07	95.53	41,578.28
NGL-2	NGL Thermal Oxidizer No. 2	41,449.69	33.07	95.53	41,578.28
NGL-3	NGL Emergency Flare	168.45	0.07	0.10	168.61
NGL-4	NGL Cooling Tower	208.52	0.00	0.00	208.52
NGL-5	NGL Process Area Fugitives	0.43	7.51	0.00	7.94
NGL-10	Emergency Generator Diesel Engine	33.94	0.03	0.09	34.05
NGL-11	Firewater Pump Diesel Engine	16.38	0.01	0.04	16.44
NGL-12	Firewater Pump Diesel Engine	16.38	0.01	0.04	16.44
NGL-13	Firewater Pump Diesel Engine	16.38	0.01	0.04	16.44
NGL-14	Firewater Pump Diesel Engine	16.38	0.01	0.04	16.44
CG-1 and CG-2	Cogeneration Units	158,739.18	62.87	92.81	158,894.86
Totals		242,115.42	136.67	284.21	242,536.30

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REGULATORY REQUIREMENTS

OxyChem's new NGL Fractionation Facilities 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 fractionation 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 OxyChem's meeting with EPA Region 6 staff on September 7, 2011, it was stated 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):

In that same meeting the EPA requested that OxyChem 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 fractionation facilities, the EPA indicated that an approval letter from the executive director of the Texas Historical Commission (THC) will 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 fractionation facilities will result in an EJ concern. The EPA is expected to run a model to perform the EJ evaluation. EPA does not anticipate that OxyChem will need to perform any additional evaluations.

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

For the proposed fractionation facilities, the EPA has indicated that an approval letter from the National Oceanic and Atmospheric Administration-National Marine Fisheries Service (NOAA-NMFS), Habitat Conservation Division, Galveston Office will meet the EPA's MSFCMA compliance requirements. 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, in our meeting with the EPA Region 6 staff on September 7, 2011, it was confirmed that NEPA is not applicability 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 fractionation 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: J.L. (Larry) Bronold		
Title: VCM Operations Manager		
Mailing Address: P.O. Box CC		
City: Ingleside	State: TX	ZIP Code: 78362-0720
Telephone No.: (361) 776-6320	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: Natural Gas Liquids Fractionation Facilities		☒ 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: 2/1/13		
Projected Start of Operation Date: 7/1/14		
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° 53’ 12”	Longitude (nearest second): 97° 14’ 7”	

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 or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	☐ YES ☒ NO
C. Number of New Jobs: 90	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: Judith Zaffirini	District No.: 21
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 ☐ Prevention of Significant Deterioration ☒ Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐ Other:__________	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

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

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.		☐ 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 Permit ☒ To Be Determined ☐ Operational Flexibility/Off-Permit Notification ☐ Streamlined Revision for GOP ☐ None ☐		

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).	
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): 242,537 tons/yr	
Volatile Organic Compounds (VOC):	
Sulfur Dioxide (SO_2):	
Carbon Monoxide (CO):	
Nitrogen Oxides (NO_x):	
Particulate Matter (PM):	
PM 10 microns or less (PM_{10}):	
PM 2.5 microns or less ($PM_{2.5}$):	
Lead (Pb):	
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	
Telephone No.: (361) 776-6169			
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 of the city for the location where the facility is or will be located.			
Chief Executive: Mayor Victor P. Lara III			
Mailing Address: 204 W 4th Street			
City: Gregory	State: TX	ZIP Code: 78359	

V. Public Notice Information (complete if applicable) (continued)	
3. Provide the name, mailing address of the Indian Governing Body for the location where the facility is or will be located. *(continued)*	
Name of the Indian Governing Body:	
Title:	
Mailing Address:	
City: State: ZIP Code:	
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 ☐	

VII. Technical Information			
B. Are any schools located within 3,000 feet of this facility?			☐ YES ☒ NO
C. Maximum Operating Schedule:			
Hours: 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.			
Vessel Openings, Furnace Openings, Furnace Start-Up/Shut-downs, Hydroblast Pad usage, Line Breaks, Incinerator Start-up/Shutdown, Painting & Blasting, Tank Cleaning, Filter Openings, Stores Items, Temp. Portable Equipment, Cell Renewal Openings, Vacuum Trucks, Epoxy Coating & Resin Repairs, Portable Chlorine Scrubber, Cogen Start-up/Shutdown in recent EI years			
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
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard 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.***	
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: na
Company name on check:	Paid online?: ☐ YES ☐ NO
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

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: J.L. (Larry) Bronold
Signature: LBronold *Original Signature Required*
Date: 5.18.2012

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: To be assigned		Application Submittal Date: May 2012
	Company: Occidental Chemical Corporation	
RN: 100211176		Facility Location: 4133 Hwy 361
City: Gregory		County: San Patricio
Permit Unit I.D.: NGL Fractionation Facilities		Permit Name: NGL Fractionation Facilities
	Permit Activity: ☒ New Source ☐ Modification	
	Project or Process Description: Fractionation of natural gas liquids	

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	242,537
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?		2/1/13							
Five years prior to start of construction		2/1/08					contemporaneous		
Estimated start of operation		7/1/14						period	
Net contemporaneous change, including proposed project, from Table 3F. (tpy)	na	na	na	na	na	na	na	na	242,615
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.

[signature] Plant Manager 5·18·2012

Signature Title Date

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

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

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions [5]	Projected Actual Emissions	Difference (A-B)[6]	Correction[7]	Project Increase[8]
1	NGL-1	NGL-1	tba	0.00*	0.00*	41,578.28		41,578.28		41,578.28
2	NGL-2	NGL-2	tba	0.00	0.00	41,578.28		41,578.28		41,578.28
3	NGL-3	NGL-3	tba	0.00	0.00	168.61		168.61		168.61
4	NGL-4	NGL-4	tba	0.00	0.00	208.52		208.52		208.52
5	NGL-5	NGL-5	tba	0.00	0.00	7.94		7.94		7.94
6	NGL-10	NGL-10	tba	0.00	0.00	34.05		34.05		34.05
7	NGL-11	NGL-11	tba	0.00	0.00	16.44		16.44		16.44
8	NGL-12	NGL-12	tba	0.00	0.00	16.44		16.44		16.44
9	NGL-13	NGL-13	tba	0.00	0.00	16.44		16.44		16.44
10	NGL-14	NGL-14	tba	0.00	0.00	16.44		16.44		16.44
11	CG-1/CG-2	CG-1/CG-2	tba	0.00**	0.00**	158,894.86		158,894.86		158,894.86
12										
13										
								Page Subtotal[9]		242,536.30

Notes:
* New sources do not have actual or baseline emissions.
** Senior TCEQ staff explained that 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 NGL Fractionation Facilities, but they are not modified. Their increased emissions will not exceed permit limits that were previously authorized under Permit Nos. 35335 and PSD-TX-880.

TABLE 3F
PROJECT CONTEMPORANEOUS CHANGES[1]

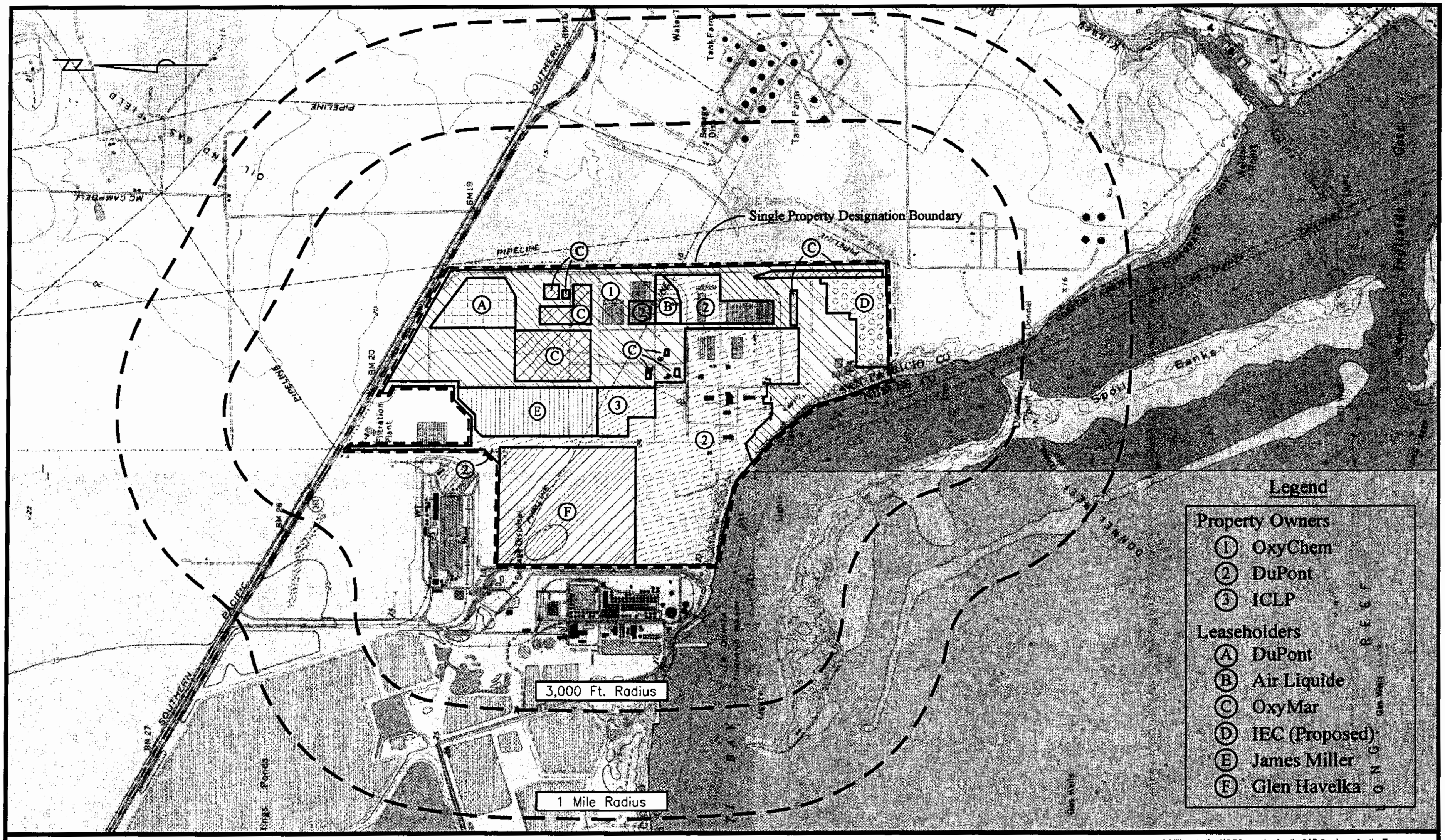
Company: Occidental Chemical Corporation	
Permit Application Number: To be assigned	**Criteria Pollutant:** GHG

	Project Date[2]	Facility at Which Emission Change Occured[3] FIN	EPN	Permit No.	Project Name or Activity	A Baseline Period	B Baseline Emissions (tons/year)	Proposed Emissions (tons/year)	Difference (A-B)[5]	Creditable Decrease or Increase[6]
1	7/2014	NGL-1 thru 14; CG-1 and CG-2	NGL-1 thru 14; CG-1 and CG-2	To be assigned	NGL Fract. Facilities	1/10-12/11	0.00	242,536.30	242, 536.30	242, 536.30
2	2/2009	CL-EMGEN2	263	2339A	E. Gen Replace. PBR	1/07-12/08	na*	44.03	44.03	44.03
3	2/2009	CL-EMGEN1	354	2339A	E. Gen Replace. PBR	1/07-12/08	na*	34.05	34.05	34.05
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
						Page Subtotal[7]				242,614.38
									Project Emission	242, 614.38
Summary of Contemporaneous Changes							**Total**			242, 614.38

Notes:
* Intermittent MSS activities and low emissions cause this baseline emission to not be a concern.

Occidental Chemical Corporation
May 2012

APPENDIX B
AREA MAP, PLOT PLAN AND OTHER SUPPORTING DOCUMENTS



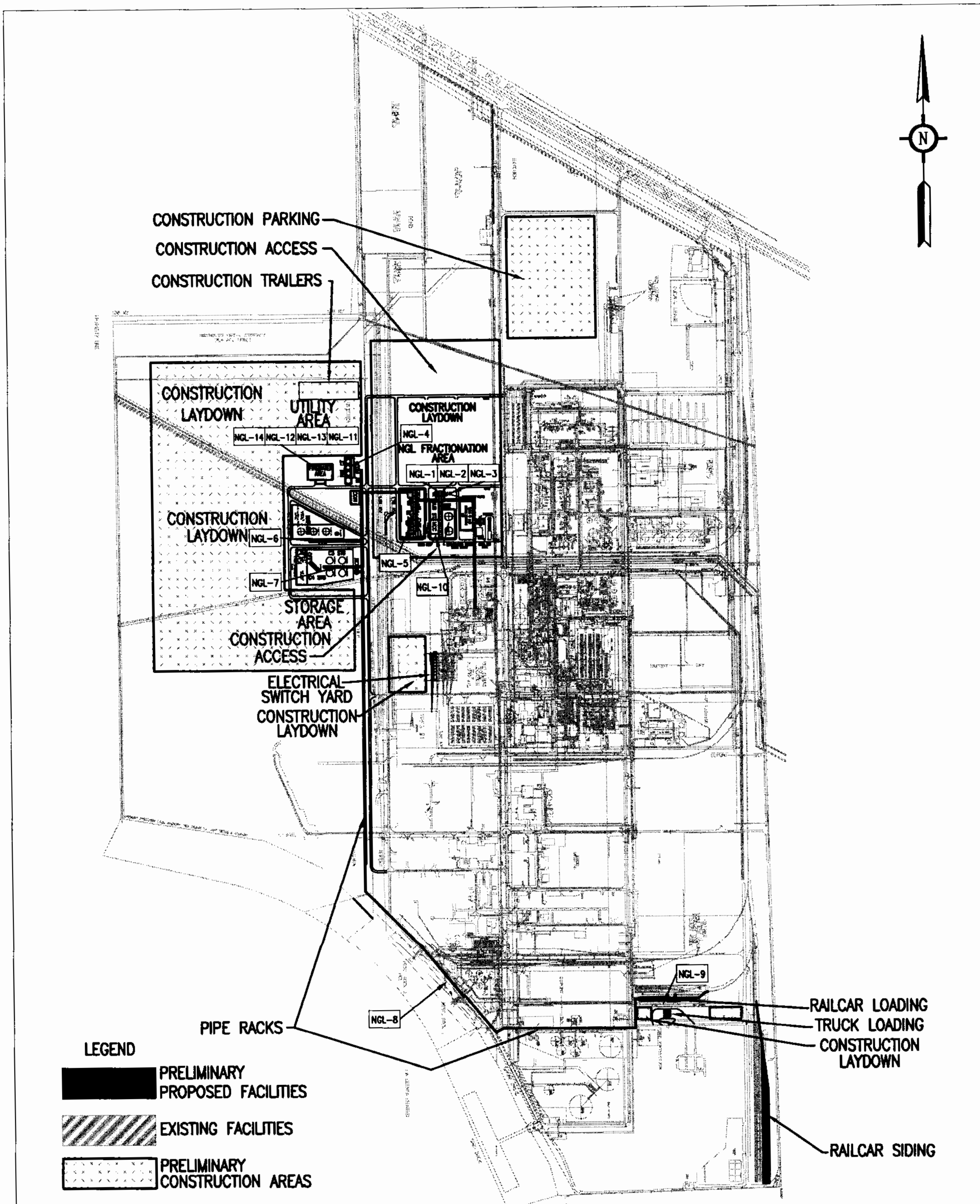
Additions to the USGS map by Austin CAD Services, Austin, Texas

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

1/2 0 1 MILE
1000 0 1000 2000 3000 4000 5000 6000 7000 FEET
1 .5 0 1 KILOMETER

QUADRANGLE LOCATION

UTM GRID AND 1975 MAGNETIC NORTH DECLINATION AT CENTER OF SHEET



0 500 1000 1500

SCALE (FT)

Occidental Chemical Corporation

A subsidiary of Occidental Petroleum Corporation

CB&I

REV.	ISSUE DATE	DESCRIPTION	PROC ENGR	LPE	PDM	PM
0	02MAR 2012	ISSUE FOR EMISSIONS SOURCES	SW			TS

TITLE: INGLESIDE FRACTIONATION FACILITY

EMISSION SOURCES

LOCATION: INGLESIDE TX

DWG NO.: 179973-000-PI-08-000005 SHEET 1 OF 1

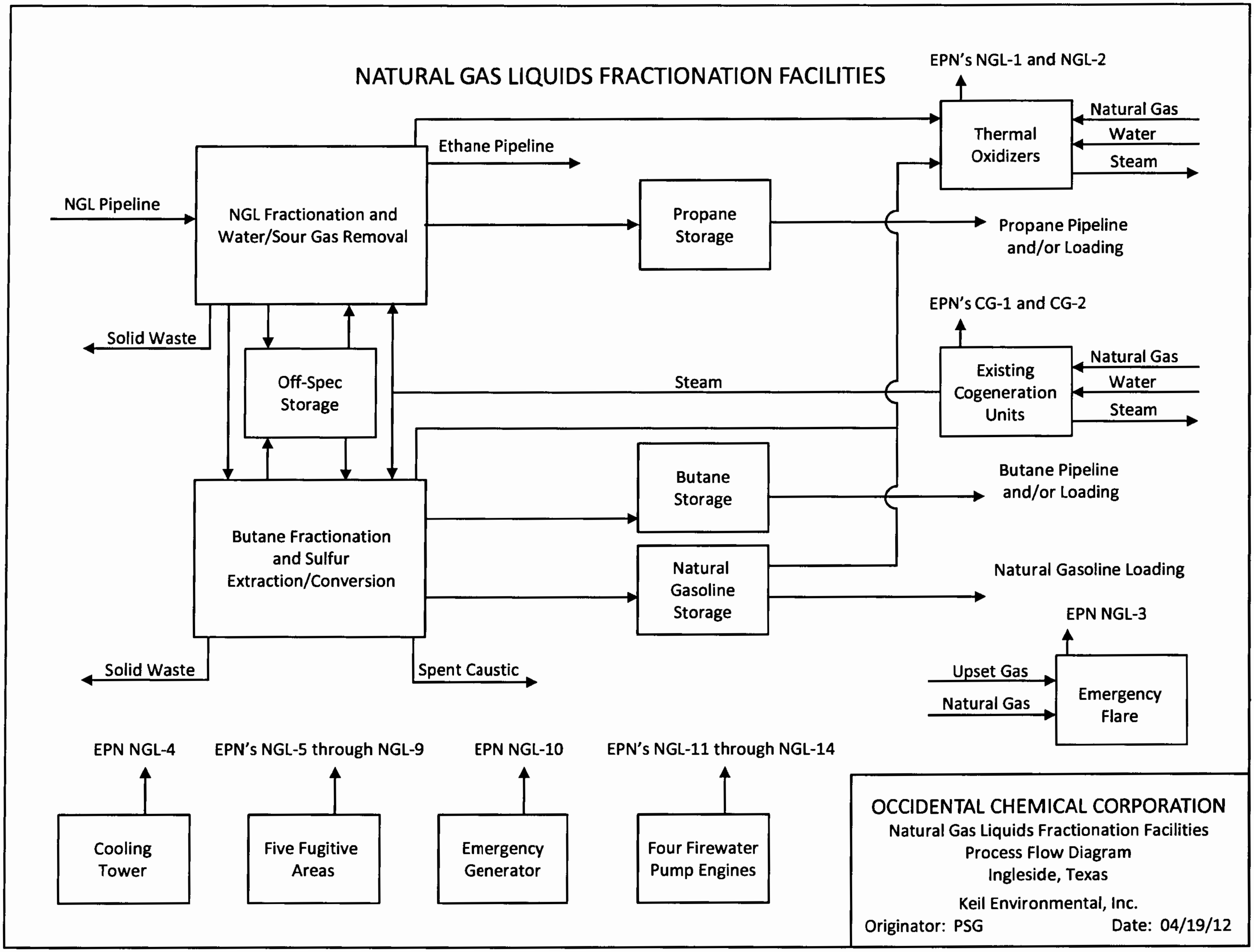

NATURAL GAS LIQUIDS FRACTIONATION FACILITIES
EPN's NGL-1 and NGL-2
Thermal Oxidizers
Natural Gas
Water
Steam
Ethane Pipeline
NGL Pipeline
NGL Fractionation and Water/Sour Gas Removal
Propane Storage
Propane Pipeline and/or Loading
EPN's CG-1 and CG-2
Solid Waste
Off-Spec Storage
Steam
Existing Cogeneration Units
Natural Gas
Water
Steam
Butane Storage
Butane Pipeline and/or Loading
Butane Fractionation and Sulfur Extraction/Conversion
Natural Gasoline Storage
Natural Gasoline Loading
EPN NGL-3
Solid Waste
Spent Caustic
Upset Gas
Natural Gas
Emergency Flare
EPN NGL-4
EPN's NGL-5 through NGL-9
EPN NGL-10
EPN's NGL-11 through NGL-14
Cooling Tower
Five Fugitive Areas
Emergency Generator
Four Firewater Pump Engines
OCCIDENTAL CHEMICAL CORPORATION
Natural Gas Liquids Fractionation Facilities
Process Flow Diagram
Ingleside, Texas
Keil Environmental, Inc.
Originator: PSG
Date: 04/19/12

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					
Natural Gas Liquids		605,500 lb/hr		X	
2. Fuels - Input					
Natural Gas		2,000 scfm		X	
3. Products & Byproducts - Output					
Ethane		185,000 lb/hr		X	
Propane		204,800 lb/hr		X	
Butane		126,800 lb/hr		X	
Natural Gasoline		87,900 lb/hr		X	
4. Solid Wastes - Output					
Filters and Misc. Solid Waste		10,000 lb/yr		X	
5. Liquid Wastes - Output					
Thermal Oxidizer Blow Down, Waste Oil, Waste Water, and Other Misc. Liquid Waste		2,300 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, SO_2, SO_3, H_2SO_4, H_2S, 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
NGL-1	NGL Thermal Oxidizer No. 1	41,449.69	1.57	0.31	1	21	310	41,449.69	33.07	95.53	41,578.28
NGL-2	NGL Thermal Oxidizer No. 2	41,449.69	1.57	0.31	1	21	310	41,449.69	33.07	95.53	41,578.28
NGL-3	NGL Emergency Flare	168.45	0.003	0.0003	1	21	310	168.45	0.07	0.10	168.61
NGL-4	NGL Cooling Tower	208.52	0.000	0.0000	1	21	310	208.52	0.00	0.00	208.52
NGL-5	NGL Process Area Fugitives	0.43	0.36	0.00	1	21	310	0.43	7.51	0.00	7.94
NGL-10	Emergency Generator Diesel Engine	33.94	0.0014	0.0003	1	21	310	33.94	0.03	0.09	34.05
NGL-11	Firewater Pump Diesel Engine	16.38	0.0007	0.0001	1	21	310	16.38	0.01	0.04	16.44
NGL-12	Firewater Pump Diesel Engine	16.38	0.0007	0.0001	1	21	310	16.38	0.01	0.04	16.44
NGL-13	Firewater Pump Diesel Engine	16.38	0.0007	0.0001	1	21	310	16.38	0.01	0.04	16.44
NGL-14	Firewater Pump Diesel Engine	16.38	0.0007	0.0001	1	21	310	16.38	0.01	0.04	16.44
CG-1 and CG-2	Cogeneration Units	158,739.18	2.99	0.30	1	21	310	158,739.18	62.87	92.81	158,894.86
Totals								242,115.42	136.67	284.21	242,536.30
Contemporaneous Sources											
263	Emergency Generator Diesel Engine	43.89	0.002	0.0004	1	21	310	43.89	0.04	0.11	44.03
354	Emergency Generator Diesel Engine	33.94	0.001	0.0003	1	21	310	33.94	0.03	0.09	34.05
Totals								77.82	0.07	0.20	78.09
Contemp. Total											242,614.39
Existing Cogen Units											
CG-1	Cogeneration Unit	1,174,669.90	22.16	2.22	1	21	310	1,174,669.90	465.26	686.81	1,175,821.97
CG-2	Cogeneration Unit	1,174,669.90	22.16	2.22	1	21	310	1,174,669.90	465.26	686.81	1,175,821.97
Totals								2,349,339.80	930.52	1,373.62	2,351,643.95

NGL Thermal Oxidizers

EPN's NGL-1 and NGL-2

Estimated Emissions Based on Maximum Waste Gas Firing

Basis:

7.03 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)
1,485.00 lb/hr CO2 venting from the amine and glycol processes
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 @60 F)	Higher Heating Value (Btu/lb)	Normal Venting (lb/hr)	Additional Peak Venting (lb/hr)	Total Heating Value (MM Btu/yr)	No. of Carbons per Molecule	Annual CO_2 Emissions (tons/yr)
Methane	16.04	1,010.0	23,865	0.67		140	1	8.05
Ethane	30.07	1,769.7	22,305	159.02		31,071	2	2,038.78
Propane	44.10	2,516.1	21,625	67.85		12,853	3	889.76
i-Butane	58.12	3,251.9	21,205	4.25	500.00	93,666	4	6,689.40
n-Butane	58.12	3,262.9	21,276	91.39	500.00	110,223	4	7,845.35
i-Pentane	72.15	4,000.9	21,017	520.72		95,866	5	6,956.00
n-Pentane	72.15	4,008.9	21,059	345.19		63,679	5	4,611.29
n-Hexane	86.18	4,755.9	20,916	113.86		20,862	6	1,528.11
n-Heptane	100.20	5,502.5	20,812	17.27		3,149	7	232.58
n-Octane	114.23	6,248.9	20,733	6.25		1,135	8	84.36
Benzene	78.11	17,989.0	87,281	25.43		19,440	6	376.46
Toluene	92.14	18,250.0	75,067	3.83		2,515	7	56.02
p-Xylene	106.17	18,444.0	65,842	1.48		855	8	21.53
H2S	34.08	589.2	6,552	0.60		34	0	0.00
COS	60.07	623.7	3,935	0.34		12	1	1.09
Methyl Mercaptan	48.10	1,402.9	11,054	0.26		25	1	1.04
Ethyl Mercaptan	62.13	2,458.9	15,000	0.05		7	2	0.31
Di-Methyl Sulfide	62.13	2,163.8	13,200	0.27		32	2	1.70
Di-Methyl Disulfide	94.19	na	na	0.41		na	2	1.68
Di-Ethyl Disulfide	122.24	na	na	0.26		na	4	1.64
Diethanol Amine	105.14	2,993.3	10,790	0.02		2	4	0.13
Triethylene Glycol	150.17	4,037.4	10,190	0.04		4	6	0.31
Totals						455,569		31,345.60
					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	61,583		3,599.79
CO_2 - waste gas								31,345.60
CO_2 - process							1,485.00	6,504.30
CO_2 - total								41,449.69
CH_4 - fuel gas					0.002	61,583		0.07
CH_4 - waste gas					0.007	455,569		1.51
CH_4 - total								1.57
N_2O - fuel gas					0.0002	61,583		0.01
N_2O - waste gas					0.001	455,569		0.30
N_2O - total								0.31

Calculation methods:

Annual CO2 emissions (tons/yr) = (normal venting (lb/hr) + additional peak venting (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 fuel firing rate (MM Btu/hr) x 1 ton/2,000 lb x 8,760 hr/yr

NGL Emergency Flare

EPN NGL-3

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 (ton/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

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NGL Cooling Tower

EPN NGL-4

Basis:

300,000 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 (ton/yr)
CO_2	66.00	47.61	208.52

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

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NGL Process Area Fugitives
EPN NGL-5

These fugitive components are associated with the NGL Fractionation Facilities. Emissions are controlled 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 SOCMI w/o C2

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	1,553	0.0089	97	0.4147	1.8162
	VAL - G/V exempt		0.0089	0		
	VAL - LL	1,548	0.0035	97	0.1625	0.7119
	VAL - LL exempt		0.0035	0		
	VAL - HL	349	0.0007	0	0.2443	1.0700
	PS - LL - MS		0.0386	100		
	PS - LL	0	0.0386	93	0.0000	0.0000
	PS - HL - MS		0.0161	100		
	PS - HL	12	0.0161	0	0.1932	0.8462
	FL - G/V quarterly	4,230	0.0029	97	0.3680	1.6119
	FL - G/V annual		0.0029	75		
	FL - G/V weekly		0.0029	30		
	FL - G/V exempt		0.0029	0		
	FL - LL quarterly	4,542	0.0005	97	0.0681	0.2984
	FL - LL annual		0.0005	75		
	FL - LL weekly		0.0005	30		
	FL - LL exempt		0.0005	0		
	FL - HL	999	0.00007	30	0.0490	0.2144
	PRV	12	0.2293	97	0.0825	0.3616
	CS	0	0.5027	95	0.0000	0.0000
	AS - LL/V		0.0386	100		
Total		**13,245**			**1.5823**	**6.9306**

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	Compressor/Blower Seals
AS - LL/V	Agitator Seals in Light Liquid or Vapor Service w/Barrier Fluid

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NGL Fugitive Emissions Summary

Constituents	NGL Process Area Fugitives, NGL-5		Gasoline Storage Area Fugitives, NGL-6		LPG Storage Area Fugitives, NGL-7		Barge Loading Area Fugitives, NGL-8		Rail Car and Truck Loading Area Fugitives, NGL-9	
	Weight Fraction	**Emission (lb/hr)**	**Weight Fraction**	**Emission (lb/hr)**	**Weight Fraction**	**Emission (lb/hr)**	**Weight Fraction**	**Emission (lb/hr)**	**Weight Fraction**	**Emission (lb/hr)**
	1.0000	**1.5823**	**1.0000**	**0.2295**	**1.0000**	**0.1769**	**1.0000**	**0.0844**	**1.0000**	**0.1118**
Methane	0.0516	0.0816	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Ethane	0.2125	0.3362	0.0000	0.0000	0.0080	0.0014	0.0013	0.0001	0.0045	0.0005
Propane	0.1293	0.2047	0.0000	0.0000	0.9697	0.1716	0.1582	0.0134	0.5547	0.0620
Iso-Butane	0.0399	0.0631	0.0016	0.0004	0.0208	0.0037	0.0898	0.0076	0.2385	0.0267
Normal Butane	0.0381	0.0603	0.0673	0.0155	0.0013	0.0002	0.1198	0.0101	0.1952	0.0218
Iso Pentane	0.0728	0.1152	0.4364	0.1002	0.0000	0.0000	0.3003	0.0254	0.0061	0.0007
Normal Pentane	0.0609	0.0964	0.2987	0.0685	0.0000	0.0000	0.2034	0.0172	0.0008	0.0001
Normal Hexane	0.0573	0.0907	0.1185	0.0272	0.0000	0.0000	0.0782	0.0066	0.0000	0.0000
Heptanes	0.0254	0.0402	0.0273	0.0063	0.0000	0.0000	0.0172	0.0015	0.0000	0.0000
Octanes	0.0264	0.0418	0.0194	0.0045	0.0000	0.0000	0.0116	0.0010	0.0000	0.0000
Benzene	0.0120	0.0190	0.0241	0.0055	0.0000	0.0000	0.0159	0.0013	0.0000	0.0000
Toluene	0.0047	0.0074	0.0047	0.0011	0.0000	0.0000	0.0029	0.0002	0.0000	0.0000
Xylene	0.0023	0.0037	0.0016	0.0004	0.0000	0.0000	0.0009	0.0001	0.0000	0.0000
H2O	0.1117	0.1767	0.0001	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000
CO2	0.0620	0.0981	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2S	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Methyl Mercaptan	0.0000	0.0001	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0001	0.0000
Ethyl Mercaptan	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0001	0.0000
Iso Propyl Mercaptan	0.0002	0.0002	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Methyl Isopropyl Mercaptan	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Di-methyl Sulfide	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Dimethyl Sisulfide	0.0021	0.0034	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Diethyl Disulfide	0.0021	0.0034	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
TEG	0.0437	0.0691	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
DEA	0.0448	0.0709	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total		1.5823		0.2295		0.1769		0.0844		0.1118

Methane (CH4)		0.0816		0.0000		0.0000		0.0000		0.0000
Ethane		0.3362		0.0000		0.0014		0.0001		0.0005
H2O		0.1767		0.0000		0.0000		0.0000		0.0000
CO2		0.0981		0.0000		0.0000		0.0000		0.0000
VOC		0.8896		0.2295		0.1755		0.0843		0.1113
All Constituent Total (lb/hr)		1.5823		0.2295		0.1769		0.0844		0.1118
CH4 (ton/yr)		0.3574		0.0000		0.0000		0.0000		0.0000
CO2 (ton/yr)		0.4299		0.0000		0.0000		0.0000		0.0000

NGL Emergency Generator and Firewater Pump Engines
EPN's NGL-10, NGL-11, NGL-12, NGL-13 and NGL-14

Basis:

58 gal/hr of diesel fired in 1,200 HP engine
28 gal/hr of diesel fired in 500 HP engines
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)

Engine	Diesel Consumption (gal/hr)	MSS Annual Hours of Operation (hr/yr)	Pollutant	Emission Factor (lb/MM Btu)	Emissions (tons/yr)
NGL-10 Emergency Generator Diesel Engine (1,200 HP)	58	52.0	CO_2	163.08	33.9380
			CH_4	0.007	0.0014
			N_2O	0.001	0.0003
NGL-11 Firewater Pump Diesel Engine (500 HP)	28	52.0	CO_2	163.08	16.3838
			CH_4	0.007	0.0007
			N_2O	0.001	0.0001
NGL-12 Firewater Pump Diesel Engine (500 HP)	28	52.0	CO_2	163.08	16.3838
			CH_4	0.007	0.0007
			N_2O	0.001	0.0001
NGL-13 Firewater Pump Diesel Engine (500 HP)	28	52.0	CO_2	163.08	16.3838
			CH_4	0.007	0.0007
			N_2O	0.001	0.0001
NGL-14 Firewater Pump Diesel Engine (500 HP)	28	52.0	CO_2	163.08	16.3838
			CH_4	0.007	0.0007
			N_2O	0.001	0.0001
Total Emissions			CO_2		99.4734
			CH_4		0.0040
			N_2O		0.0008

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

Cogeneration Units - Proposed GHG Increased Emissions

EPN's CG-1 and CG-2

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

Basis:

310 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	36,241.82	158,739.18
CH_4	0.002	0.68	2.99
N_2O	0.0002	0.07	0.30

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 x 8,760 hr/yr

Chlor-Alkali Emergency Generator Engines
EPN's 263 and 354

Basis:

75 gal/hr of diesel fired in 1,500 HP engine
58 gal/hr of diesel fired in 1,200 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)

Engine	Diesel Consumption (gal/hr)	MSS Annual Hours of Operation (hr/yr)	Pollutant	Emission Factor (lb/MM Btu)	Emissions (tons/yr)
263 Emergency Generator Diesel Engine (1,500 HP)	75	52.0	CO_2	163.08	43.8853
			CH_4	0.007	0.0018
			N_2O	0.001	0.0004
354 Emergency Generator Diesel Engine (1,200 HP)	58	52.0	CO_2	163.08	33.9380
			CH_4	0.007	0.0014
			N_2O	0.001	0.0003
Total Emissions			CO_2		77.8233
			CH_4		0.0032
			N_2O		0.0006

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

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Cogeneration Units - Maximum Existing GHG Emissions

EPN's CG-1 and CG-2

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

Basis:

1,930 MM Btu/hr, maximum natural gas firing rate authorized for each gas turbine
364 MM Btu/hr, maximum natural gas firing rate authorized for each heat recovery steam generator (HRSG)
0 MM Btu/hr attributed to hydrogen fuel firing in each HRSG since GHG emissions are not expected from hydrogen combustion
2,294 MM Btu/hr total fuel firing rate for each cogen unit
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 cogeneration unit and assume maximum natural gas fuel firing, as authorized in the current PSD permit

Pollutant	Emission Factor (lb/MM Btu)	Hourly Emissions (lb/hr)	Annual Emissions (tons/yr)
CO_2	116.91	268,189.48	1,174,669.90
CH_4	0.002	5.06	22.16
N_2O	0.0002	0.51	2.22

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 x 8,760 hr/yr

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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 fractionation facilities, this BACT review is applied to the thermal oxidizers, the flare, the fugitive monitoring and maintenance program and the diesel-fired engines. 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.

NGL Thermal Oxidizers (EPN's NGL-1 and NGL-2)

1) The identification of available control technologies. Non-condensable vent streams from the NGL fractionation process and loading areas 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) Heater 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 heater exhaust to preheat the combustion air or produce steam for use at the site, thereby offsetting GHG emissions from other fuel combustion sources.

e) Process CO_2 capture and storage – Capture, compression, transport and geological storage or use of CO_2 rich vent streams rather than combustion.

f) 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, heater 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 83,000 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 NGL Fractionation Facilities. 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 17,000 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.

The amount of CO_2 in the NGL feed stream that is removed and concentrated in the amine regenerator is about 6,500 tons/yr. This concentrated CO_2 rich stream could be dried, compressed and routed to oil production facilities using enhanced oil recovery. Again, the nearest location for this enhanced oil recovery would be in Hastings. This approach is considered the next least effective control technology based on the reduction of GHG emissions. Combustor design, heater 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 83,000 tons/yr, but would require an additional 118 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 74,500 tons/yr.

Consequently, the net overall reduction in GHG emissions would be 8,000 tons/yr. The additional capital cost of the recovery and compression equipment and the pipeline is estimated to be about $300,000,000. Significant potential corrosion issues and material selection requirements would be created by the sulfur dioxide in the flue gas. The cost represents about $37,000 per ton of GHG. These costs would exceed values that would make the overall project economically viable and are 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 $5,000,000 and will save approximately $800,000 annually in fuel costs, while reducing GHG emissions by 17,000 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.

The capture, compression and sequestration of the amine regenerator vent stream is estimated to cost about $230,000,000. The bulk of this cost would be for a pipeline to Hastings. This level of control represents about $35,400 per ton of GHG. Again, these costs would exceed values that would make the overall project economically viable.

Combustor design, heater 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 heater design efficiency, heater 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.

NGL Emergency Flare (EPN NGL-3)

1) The identification of available control technologies. The flare is used as a back-up device to the thermal oxidizers. It is used only during emergency periods when the thermal oxidizers are unavailable to process the vent gases from the fractionation unit, storage and loading areas. 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 quantity of vent gas to be flared and minimizing the size and number of the pilots. Potential GHG emission control technologies for the emergency flare are identified as follows:

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.

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

d) 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. 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.

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. This option is considered the next most effective technology.

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

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 $5,000,000. 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.

High efficiency pilots reduce natural gas consumption as well as GHG emissions and do not cost more than larger traditional pilots. Consequently 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.

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. The use of high efficiency pilots, pilot flame monitoring and flare gas feed controls will also 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. Feed flow meters and temperature monitors inside the enclosed flare will provide rapid indication when the unit is operating. Natural gas will be added to the feed to assure adequate heating values for effective combustion.

NGL Cooling Tower (EPN NGL-4)

1) The identification of available control technologies. The cooling requirements for the NGL Fractionation Facilities 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 NGL 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 209 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 209 tons per year of CO_2 emissions from the cooling tower; however, it would significantly increase the power and thermal energy requirements for the NGL Fractionation Facilities. 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 NGL 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 209 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 2 MM Btu/hr of natural gas firing at the cogeneration facilities, increasing the GHG emissions by 1,024 tons per year. These GHG emissions more than off-sets the elimination of the 209 tons per year of GHG emissions from the NGL 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 100 gpm to at least 300 - 600 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 fugitive GHG emissions, none of the available control technologies are considered cost effective and BACT is determined to be no control. 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.

NGL Process Area Fugitives (EPN NGL-5)

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. 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 NGL Fractionation Facilities.

5) The selection of BACT. Due to the negligible amount of fugitive GHG emissions, none of the available control technologies are considered cost effective and BACT is determined to be no control. 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.

NGL Emergency Generator Diesel Engine and Firewater Pump Diesel Engines (EPN's NGL-10, 11, 12, 13 and 14)

1) The identification of available control technologies. The diesel-fired emergency generator engine and the four diesel-fired firewater pump engines are included in this application for the NGL Fractionation Facilities because of GHG emissions that occur during the scheduled testing of the engines. Use of these engines for emergency conditions will not be authorized by this permit since these emergency events are not subject to permitting requirements.

Natural gas-fired and electrically driven engines are also possibilities to consider; however, their availability during emergency events is not as certain as diesel-fired engines, and so, they are not considered as practical technologies for this service.

Potential GHG emission control technologies for these engines 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 these diesel engines that are 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.