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Application for Prevention of Significant Deterioration Air Permit for Greenhouse Gas Emissions

Houston Central Gas Plant
Colorado County, Sheridan, Texas

COPANO

Submitted by

Copano Processing, L.P.
Houston, Texas

Revised December 2012

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Section 1
Introduction

Copano Processing, L.P. (Copano) operates a gas processing plant and associated support facilities collectively referred to as Houston Central Gas Plant (HCP), which is located in Colorado County, Sheridan, Texas. The HCP has a gas processing capacity of 1,100 million standard cubic feet per day per day (MMSCFD) and is a major source of NO_x, CO, VOC, and greenhouse gas (GHG) emissions. Copano holds TCEQ NSR Permits Nos. 56613, 17117, 17554, 96187, and various other permits by rule (PBRs) to authorize construction of existing emission sources. Federal Operating Permit (FOP) No. O-807 authorizes on-going operations.

The company proposes to expand HCP operations by installing a new 400 MMSCFD cryogenic process train. This train will consist of inlet gas mole sieve dehydrators, two supplemental heaters (HTR-3/HTR-4), a 400 MSCFD cryogenic process, a liquid amine treating unit controlled by a new Regenerative Thermal Oxidizer (RTO-3), two (2) residue gas compressor turbines (TURB-5 and TURB-6), an amine storage tank (TANK-3), and associated fugitive components (CRYO3 FUG). There will also be a new vent stream (flash gas from LL Treater) that will be routed to the existing HCP fuel gas system.

The project qualifies for a TCEQ Non-Rule Oil and Gas Standard Permit under Title 30 Texas Administrative Code §116.620 (30 TAC §116.620). Copano has submitted a registration package to TCEQ for the Standard Permit to authorize the project. The project emissions increases and/or net emissions increases are less than the Prevention of Significant Deterioration (PSD) applicability thresholds for all pollutants except greenhouse gases (GHG). Permitting of GHG emissions in Texas is currently conducted by the USEPA Region VI; therefore, a separate PSD permit application is required to be submitted to USEPA for GHG emissions. This document constitutes Copano's application for the required GHG PSD permit. The application is organized as follows:

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

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

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

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

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

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

Section 7 is an additional impact analysis as required by 40 CFR 52.21(o).

Appendix A contains GHG emissions calculations for the affected facilities.

Appendix B contains a copy of the TCEQ Standard Permit registration package.

Section 2
Administrative Information and PSD Applicability Forms

This section contains the following forms:

- Administrative Information
- TCEQ Table 1F
- TCEQ Table 2F
- Table 3F

Tables 1F and 2F are federal NSR applicability forms. Because this application covers only GHG emissions, and permitting of other pollutants is being conducted by TCEQ, these forms only include GHG emissions. As shown in both the Table 1F and 2F, GHG emissions from the project exceed 75,000 tpy of CO_2e; therefore, a Table 3F, which includes the required netting analysis, is also included. The net increase in GHG emissions exceeds 75,000 tpy of CO_2e; therefore, PSD review is required.

Administrative Information

A. Company or Other Legal Name: Copano Processing, L.P.		
B. Company Official Contact Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): Mr. Rex J. Prosser		
Title: Sr. Director, EH&S Corporate		
Mailing Address: Two Allen Center, 1200 Smith Street, Suite 2300		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 713-621-9547	Fax No.: 713-737-9081	E-mail Address: rex.prosser@copano.com
C. Technical Contact Name: Mr. Rex J. Prosser		
Title: Sr. Director, EH&S Corporate		
Company Name: Copano Processing, L.P.		
Mailing Address: Two Allen Center, 1200 Smith Street, Suite 2300		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 713-621-9547	Fax No.: 713-737-9081	E-mail Address: rex.prosser@copano.com
D. Facility Location Information:		
Street Address: 1650 County Road 255 South		
If no street address, provide clear driving directions to the site in writing:		
City: Sheridan	County: Colorado	ZIP Code: 77475
E. TCEQ Account Identification Number (leave blank if new site or facility): CR-0020-R		
F. TCEQ Customer Reference Number *(leave blank if unknown)*: CN601465255		
G. TCEQ Regulated Entity Number *(leave blank if unknown)*: RN101271419		
H. Site Name: Houston Central Gas Plant		
I. Area Name/Type of Facility: Cryogenic Plant	☒ Permanent ☐ Portable	
J. Principal Company Product or Business: Natural gas processing		
K. Principal Standard Industrial Classification Code: 1321		
L. Projected Start of Construction Date: 2/01/2013	Projected Start of Operation Date: 2/01/2014	
SIGNATURE		
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief.		
NAME: Mr. Rex J. Prosser, Sr. Director, EH&S Corporate		
SIGNATURE: Rex J. Prosser *Original Signature Required*		
DATE: 12/3/12		

TCEQ

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: **TBD**	Application Submittal Date: **June, 2012, Revised December 2012**
Company: **Copano Processing L.P.**	
RN: **101271419**	Facility Location: **1650 County Road 255 South**
City: **Sheridan**	County: **Colorado**
Permit Unit I.D.: **Cryogenic Plant**	Permit Name: **Cryogenic Plant**
Permit Activity: New Source ___ Modification _X_	
Project or Process Description: **Construct new cryogenic plant at Houston Central Gas Plant**	

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS											
	Ozone		CO	PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	H_2S	TRS	Pb	Other[1]
	VOC	NO_x										GHG
Nonattainment? (yes or no)	No	No	No	No	No	No	No	No	NA	NA	No	NA
Existing site PTE (tpy)?	>100	>100	>100	>100	>100	>100	>100	>100				>100
Proposed project emission increases (tpy from 2F)[2]	NA	NA	NA	NA	NA	NA	NA	NA	0.0	0.0	0.00	201,871
Is the existing site a major source? [3]If not, is the project a major source by itself?	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Significance Level (tpy)	40	40	100	25	15	10	40	40	10	10	0.6	75,000
If site is major, is project increase significant?												Yes
If netting required, estimated start of construction?								1-Jan-12				
Five years prior to start of construction								1-Jan-07				contemporaneous
Estimated start of operation								1-Oct-13				period
Net contemporaneous change, including proposed project, from Table 3F. (tpy)												489,759
FNSR APPLICABLE? (yes or no)												Yes

1 Other PSD pollutants.

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

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

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

Signature	Senior Director, EH&S Corporate Title	12/3/12 Date

TCEQ - 10154 (Revised 10/08) Table 1F
These forms are for use by facilities subject to air quality permit requirements and may be revised periodically. (APDG 5912v1)

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant:	**GHG (CO2 Equivalents)**	**Permit No.:**	**TBD**
Baseline Period:	**NA**	**Project Name:**	**HCP Cryogenic Plant**

	Affected or Modified Facilities			Permit No.	Actual Emissions (tons/yr)	A Baseline Emissions (tons/yr)	B Proposed Emissions (tons/yr)	Projected Actual Emissions (tons/yr)	Difference (B-A) (tons/yr)	Correction (tons/yr)	Project Increase (tons/yr)
	FIN	EPN	Facility Name								
1	HTR-3	HTR-3	Supplemental Gas Heater	TBD	0	0	876.7		876.7	0.0	876.7
2	HTR-4	HTR-4	Supplemental Gas Heater	TBD	0	0	876.7		876.7	0.0	876.7
3	RTO-3	RTO-3	RTO	TBD	0	0	69,458.7		69,458.7	0.0	69,458.7
4	TURB-5	TURB-5	Solar Mars 100	TBD	0	0	65,096.8		65,096.8	0.0	65,096.8
5	TURB-6	TURB-6	Solar Mars 100	TBD	0	0	65,096.8		65,096.8	0.0	65,096.8
6	CRYO3 FUG	CRYO3 FUG	Fugitives	TBD	0	0	465.0		465.0	0.0	465.0
7											
8					-	-		-	-	-	-
9					-	-		-	-	-	-
10					-	-		-	-	-	-
11					-	-		-	-	-	-
12					-	-		-	-	-	-
13					-	-		-	-	-	-
14					-	-		-	-	-	-
15					-	-		-	-	-	-
16	-	-		-	-	-	-	-	-	-	-
										Page Subtotal[9]:	**201,870.7**
										Project Total:	**201,870.7**

Table 3F
Project Contemporaneous Changes

Company: **Copano Processing, LP**

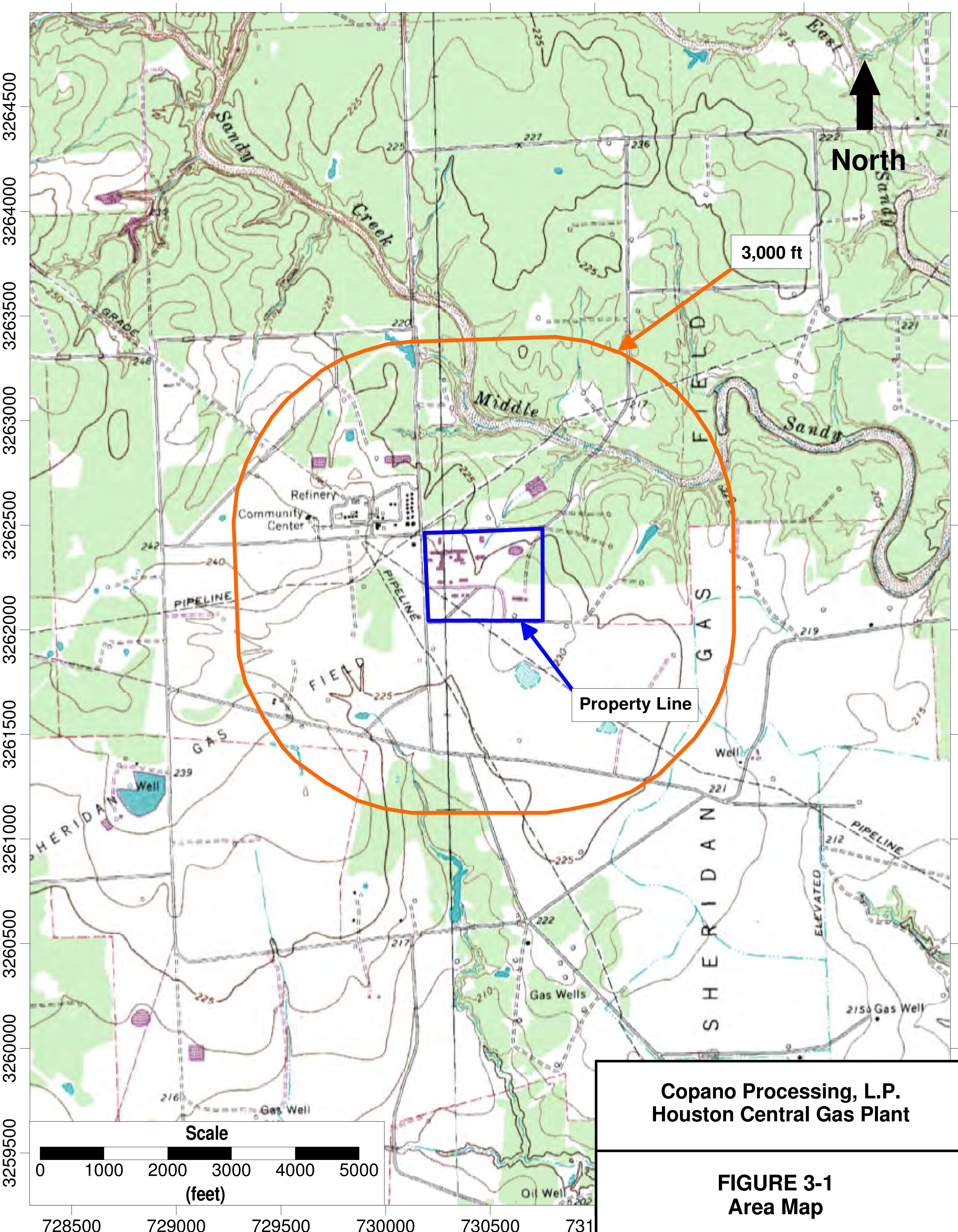
Permit Application No. **TBD**

Criteria Pollutant: **GHG**

	PROJECT DATE	EMISSION UNIT AT WHICH REDUCTION OCCURED FIN	EPN	PERMIT NUMBER	PROJECT NAME OR ACTIVITY	A PROPOSED EMISSIONS (tons / year)	B BASELINE EMISSIONS (tons / year)	C DIFFERENCE (A-B) (tons / year)	CREDITABLE DECREASE OR INCREASE (tons / year)
1	5/31/2011	TURB-3	TURB-3	96187	Solar Turbine Mars 100	58,819	0	58,819	58,819
2	5/31/2011	TURB-4	TURB-4	96187	Solar Turbine Mars 100	58,819	0	58,819	58,819
3	5/31/2011	HTR-1	HTR-1	96187	Supplemental Gas Heater	877	0	877	877
4	5/31/2011	HTR-2	HTR-2	96187	Supplemental Gas Heater	877	0	877	877
5	5/31/2011	RTO-2	RTO-2	96187	Regenerative Termal Oxidizer	58,010	0	58,010	58,010
6	1/24/2008	STKBLR3	STKBLR3	56613	Steam Boiler No. 3	110,487	0	110,487	110,487
7	1/1/2013	HTR-3	HTR-3	TBD	New Cryogenic Plant	877	0	877	877
8	1/1/2013	HTR-4	HTR-4	TBD	New Cryogenic Plant	877	0	877	877
9	1/1/2013	RTO-3	RTO-3	TBD	New Cryogenic Plant	69,459	0	69,459	69,459
10	1/1/2013	TURB-5	TURB-5	TBD	New Cryogenic Plant	65,097	0	65,097	65,097
11	1/1/2013	TURB-6	TURB-6	TBD	New Cryogenic Plant	65,097	0	65,097	65,097
12	1/1/2013	CRYO3 FUG	CRYO3 FUG	TBD	New Cryogenic Plant	465	0	465	465
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
								PAGE SUBTOTAL:	489,759
	Summary of Contemporaneous Changes							TOTAL :	489,759

Section 3
Area Map and Plot Plan

An Area Map showing the location of the Houston Central Gas Plant is presented in Figure 3-1. A plot plan showing the location of the proposed facilities is presented in Figure 3-2.

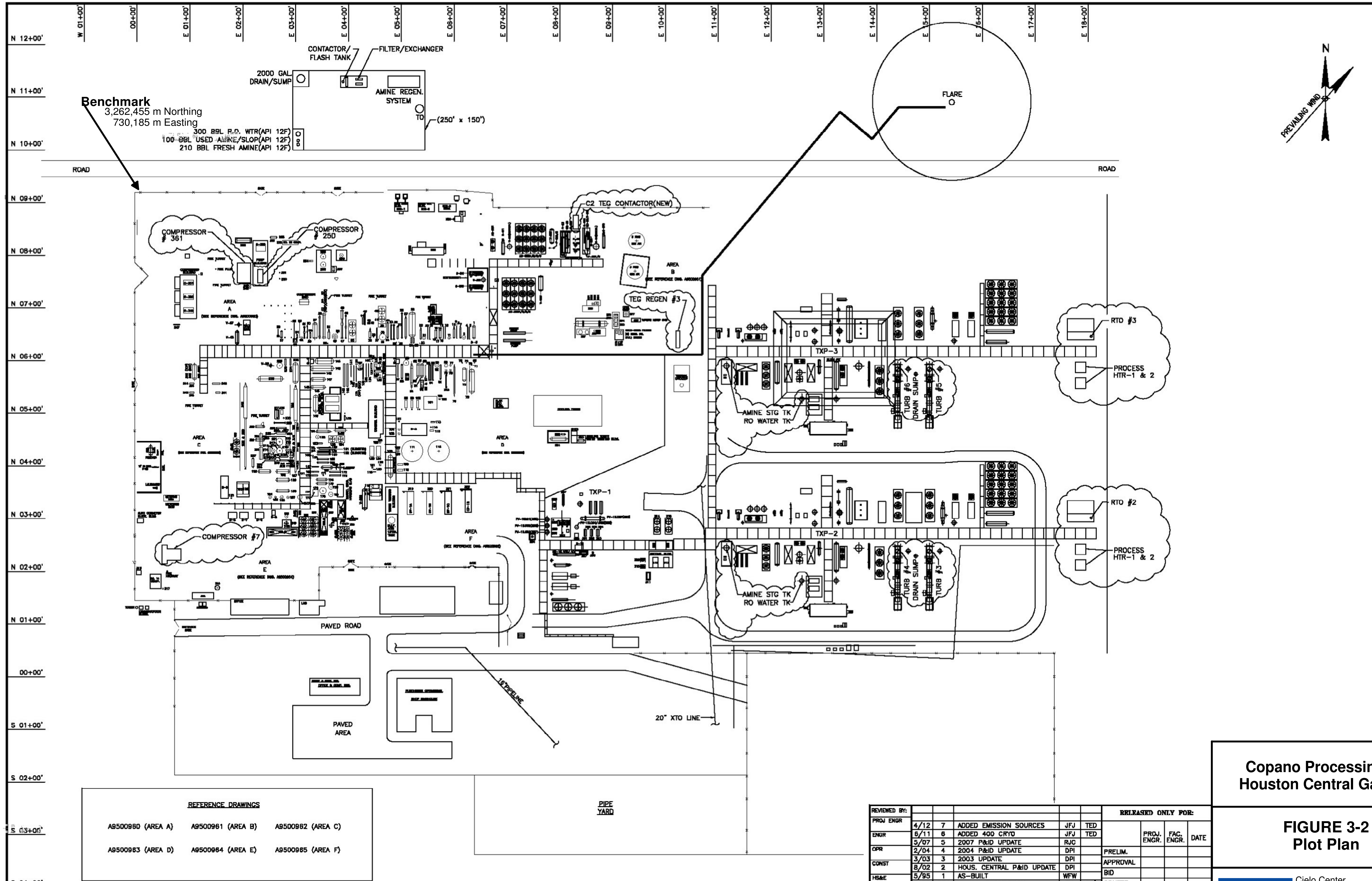


Source: mytopo.com/
Zone: 14
Coordinate Datum: NAD 83

Copano Processing, L.P.
Houston Central Gas Plant

FIGURE 3-1
Area Map

RPS
Cielo Center
1250 South Capital of Texas Highway
Building Three, Suite 200
Austin, Texas 78746, USA



REVIEWED BY:					
PROJ ENGR	4/12	7	ADDED EMISSION SOURCES	JFJ	TED
ENGR	6/11	6	ADDED 400 CRYO	JFJ	TED
	5/07	5	2007 P&ID UPDATE	RJC	
OPR	2/04	4	2004 P&ID UPDATE	DPI	
	3/03	3	2003 UPDATE	DPI	
CONST	8/02	2	HOUS. CENTRAL P&ID UPDATE	DPI	
HS&E	5/95	1	AS-BUILT	WFW	
	DATE	REV	DESCRIPTION	BY	APP'D

RELEASED ONLY FOR:	PROJ. ENGR.	FAC. ENGR.	DATE
PRELIM.			
APPROVAL			
BID			
CONSTR.			

Copano Processing, L.P.
Houston Central Gas Plant

FIGURE 3-2
Plot Plan

RPS
Cielo Center
1250 South Capital of Texas Highway
Building Three, Suite 200
Austin, Texas 78746, USA

Section 4
Process Description

4.1 Proposed New Equipment

Copano Processing, L.P. owns and operates the Houston Central Gas Plant (HCP), which is a natural gas processing, treatment, and fractionation facility that has a current nameplate capacity of 1,100 million standard cubic feet per day (MMSCFD). Copano is proposing to add an additional 400 MMSCFD cryogenic process, bringing the total plant capacity up to 1.5 billion standard cubic feet per day (BSCFD).

High pressure natural gas from the inlet pipeline will enter the plant, where it is first dehydrated through a molecular sieve dehydrator. After dehydration, the dry gas will then be processed through a cryogenic process, removing the natural gas liquids (NGLs) from the gas. The NGLs are then sent through the site's existing fractionation columns. The residue gas from the cryogenic process will then be compressed and sent to sales. The compressors are driven by two new gas-fired combustion turbines. The liquids will be treated in a liquid amine treating unit (LL Treater), where CO_2 and trace amounts of H_2S will be removed from the NGLs. The acid gas (mostly CO_2 along with minor concentrations of H_2S and hydrocarbons) will then be routed to a new regenerative thermal oxidizer.

New project air emission sources consist of two supplemental gas-fired heaters (HTR-3 and HTR-4), a LL Treater controlled by a new Regenerative Thermal Oxidizer (RTO-3), an amine storage tank (TANK-3), two (2) Solar Mars 100 combustion turbines (TURB-5 and TURB-6) used for compression of the residue gas, and fugitive piping components (CRYO3 FUG) Flash gas from the vent from the flasher in the LL Treater process will be routed into the existing HCP fuel gas system. This will constitute a replacement of an insignificant fraction (~1.5 mmBtu/hr) of the existing fuel and will not result in an increase in the firing rate or emission rate of any existing facility. A process flow diagram for the proposed new equipment is shown in Figure 4-1.

4.2 Existing Equipment

The existing HCP processes 1,100 MMSCFD of gas. Raw natural gas enters the plant from two high pressure sources and one low pressure source. The high pressure gas sources enter the plant at 1,000 psig. The low pressure gas source (approximately 7% of total gas inlet) from field production wells enters the plant, where it is compressed by the inlet gas compressors to 1,000 psig, then sent through an amine treating unit to remove CO_2 and trace amounts of H_2S. The acid gas from the amine treating unit (mostly CO_2 along with minor concentrations of H_2S and hydrocarbons) is routed to the site's existing regenerative thermal oxidizers. The treated gas is then dehydrated by the glycol dehydration system, which consists of an ethylene glycol treater and two triethylene glycol treaters. The overhead vapors from the dehydrators are routed back to a condenser unit. Uncondensed vapors from the condenser are vented to the plant's low pressure flare system. Emissions from the dehydration system intermediate flash tanks are recycled back into the plant fuel system.

The dry, treated gas is then mixed with the two high pressure sources and sent on to a lean oil absorption process plant and a cryogenic process plant to process the natural gas and remove the NGLs. The residue gas is compressed and sent to sales. Some of the y-grade NGLs are then sent to the fractionation plant and separated into individual liquid products (ethane, propane, n-butane, isobutane, and natural gasoline (C5+)). The remaining y-grade and fractionated products are sent offsite via pipeline. The isobutene and n-butane are sent offsite via truck.

Steam generated from utility boilers is used for various processes in the plant, such as regenerating spent glycol in the dehydration system. A wastewater basin is used to collect wastewater runoff. This wastewater runoff is then treated with an API oil and water separator. There will be no change to these existing systems from this proposed expansion. A process flow diagram for the existing process is shown in Figure 4-2.

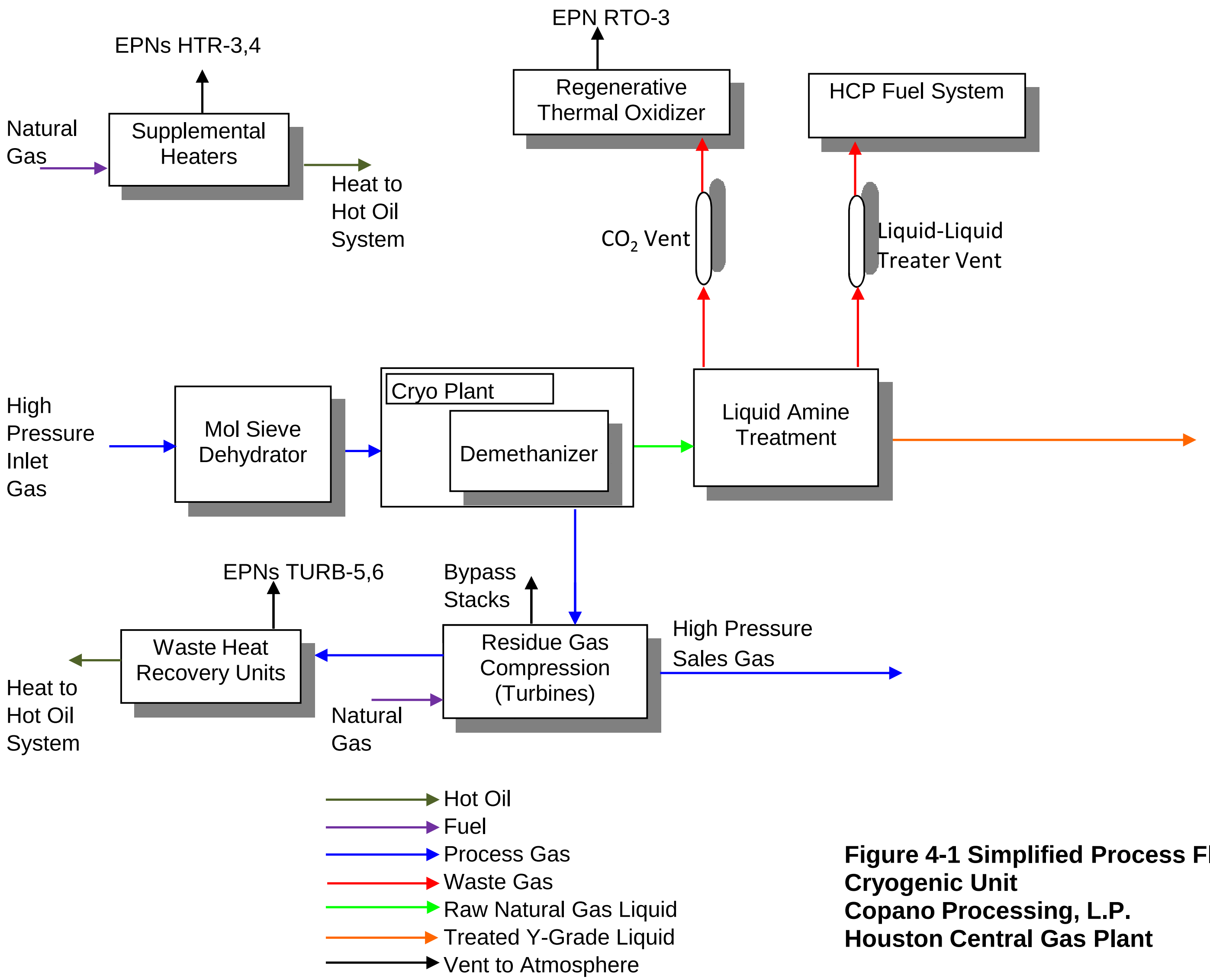
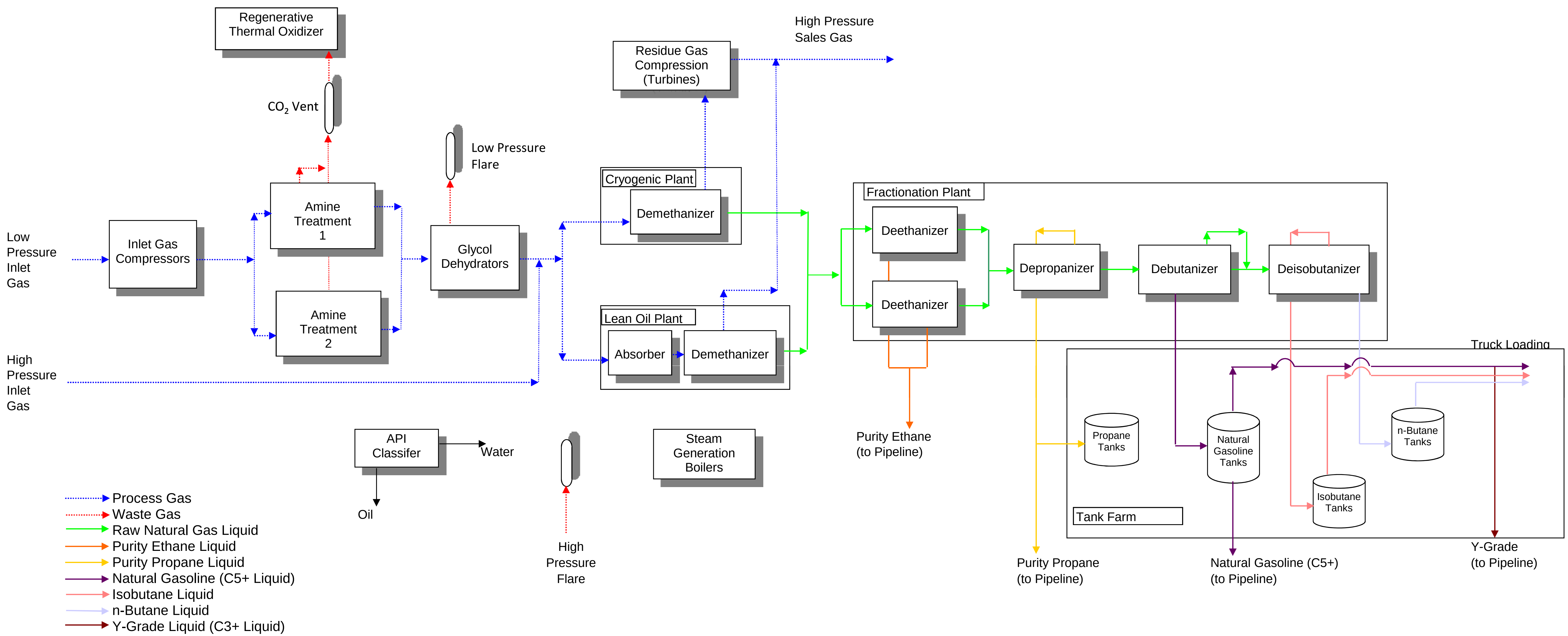


Figure 4-1 Simplified Process Flow Diagram - Cryogenic Unit
Copano Processing, L.P.
Houston Central Gas Plant

Figure 4-2 Simplified Process Flow Diagram - Existing Facilities
Copano Processing, L.P.
Houston Central Gas Plant



Section 5
Emission Rate Basis

This section contains a description of the increases in GHG emissions from new facilities associated with the project. GHG emission calculations methods are also described, and the resulting GHG emission rates are presented in Table 5-1 for each emission point. Emissions calculations are included in Appendix A.

5.1 Combustion Turbines

There will be two new natural gas fired combustion turbines used for residue gas compression included for the project (EPNs TURB-5 and TURB-6). The compressor turbines are Solar Mars 100 combustion turbines that each has a nominal rated capacity of 15,000 HP.

Annual GHG emissions were calculated based on the maximum fuel firing rate of each turbine occurring continuously (8,760 hr/yr) all year. Emissions of CO_2, CH_4, and N_2O were calculated using the default emission factors for natural gas from Tables C-1 and C-2 of Appendix A to 40 CFR Part 98, Subpart C. The emissions calculations are included in Table A-1 of Appendix A to this permit application.

5.2 Heaters

There will be two new natural gas fired heaters (EPNs HTR-3 and HTR-4) installed to support the project. The heaters will each have a capacity of 25 MMBtu/hr (HHV) and will be operated no more than 600 hr/yr each. Emissions of CO_2, CH_4, and N_2O were calculated using the default emission factors for natural gas from Tables C-1 and C-2 of Appendix A to 40 CFR Part 98, Subpart C. The emissions calculations are included in Table A-1 of Appendix A to this permit application.

5.3 RTO

The new RTO used to control trace VOC and H_2S in the acid gas stream from the amine unit will emit CO_2 that is in the acid gas as well as CO_2 from combustion of the VOCs in the stream and CO_2 and other GHGs from combustion of natural gas burned in the pilots. CO_2 emissions from the CO_2 in the vent stream were calculated by multiplying the inlet CO_2 concentration by the flow rate of the stream. CO_2 emissions from oxidation of the VOCs were calculated from the inlet VOC composition and 100% conversion of each compound to CO_2. Emissions of CO_2,

CH_4, and N_2O from natural gas burned in the pilots were calculated using the default emission factors for natural gas from Tables C-1 and C-2 of Appendix A to 40 CFR Part 98, Subpart C. The emissions calculations are included in Table A-2 of Appendix A to this permit application.

5.4 Process Fugitive Emissions

Process fugitive (equipment leak) emissions consist of methane from the new piping components in the new cryogenic plant (EPN CRYO3 FUG). The 28M leak detection and repair (LDAR) program will be applied to the new piping components associated with the Project. All emissions calculations utilize current TCEQ factors and methods in the TCEQ's *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.* Each fugitive component was classified first by equipment type (valve, pump, relief valve, etc.) and then by material type (gas/vapor, light liquid, heavy liquid). Uncontrolled emission rates were obtained by multiplying the number of fugitive components of a particular equipment/material type by the appropriate Oil and Gas Production Operations emission factor. To obtain controlled fugitive emission rates, the uncontrolled rates were multiplied by a control factor, which was determined by the 28M LDAR program. The methane emissions were then calculated by multiplying the total controlled emission rate by the weight percent of methane in the process streams. The fugitive emissions calculations are included in Table A-4 of Appendix A.

Table 5-1 Proposed GHG Emission Limits (CO_2e)

EPN	Description	tpy
HTR-3	Supplemental Gas Heater	877
HTR-4	Supplemental Gas Heater	877
RTO-3	Regenerative Thermal Oxidizer	69,459
TURB-5	Solar Mars 100	65,097
TURB-6	Solar Mars 100	65,097
CRYO3 FUG	Fugitives	465

Section 6
Best Available Control Technology

PSD regulations require that the best available control technology (BACT) be applied to each new and modified facility that emits an air pollutant for which a significant net emissions increase will occur from the source. The only PSD pollutant addressed in this permit application is GHG. The new facilities associated with the project that emit GHGs include two natural gas fired combustion turbines (EPNs TURB-5 and TURB-6), two small gas-fired heaters (EPNs HTR-4 and HTR-4), one new regenerative thermal oxidizer (EPN RTO-3), and new process fugitives (EPN CRYO3 FUG). BACT applies to each of these new and modified sources of GHG emissions.

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

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

1) Identification of available control technologies;

2) Technically infeasible alternatives are eliminated from consideration;

3) Remaining control technologies are ranked by control effectiveness;

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

5) Selection of BACT.

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

6.1 Combustion Turbines

6.1.1 Step 1 – Identification of Potential Control Technologies

A search of EPA's RACT/BACT/LAER Clearinghouse was conducted for small natural gas turbines in the size range of those proposed for Copano's new cryogenic plant, and no entries were found for GHG emissions. However, based on process and engineering knowledge and judgment and permit applications that have been submitted to EPA Region 6 for similar facilities, several potentially applicable GHG control technologies were identified for consideration in this BACT analysis. These technologies include the following:

- Periodic Maintenance and Tune-up – Periodic tune-up of the turbines to maintain optimal thermal efficiency. After several months of continuous operation of the combustion turbines, fouling and degradation results in a loss of thermal efficiency. A periodic maintenance program consisting of inspection of key equipment components and tune up of the combustor will restore performance to original or near original conditions. Solar Turbines, the manufacturer of the proposed turbines, has an extensive inspection and maintenance program that Copano implements on existing turbines at the HCP.

- Turbine Design – Good turbine design to maximize thermal efficiency.

- Instrumentation and Controls – Proper instrumentation ensures efficient turbine operation to minimize fuel consumption and resulting GHG emissions.

- Waste Heat Recovery – Use of heat recovery from the turbine exhausts to provide process heat for use at the plant.

- CO_2 Capture and Storage – Capture and compression, transport, and geologic storage of the CO_2.

6.1.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered "technically" feasible for the proposed turbines. Proper instrumentation and controls, high efficiency turbine design, waste heat recovery, and periodic maintenance and tune-ups are all used on existing turbines at the Copano HCP and have been incorporated into the design of the proposed turbines and are thus considered viable for the proposed facilities.

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

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

A project implementing CCS was in the permitting stage at the time of this application submittal. This project is the Indiana Gasification Project, and it differs from Copano's project in several significant ways. The project will gasify coal, producing significantly more CO_2 than the Copano combustion turbines, with the primary product being substitute natural gas (SNG), or methane. When coal is gasified, the product is a mixture consisting primarily of CO, CO_2, and H_2. Then, in the SNG process, a series of reactions converts the CO and H_2 to methane. To meet pipeline specifications, the CO_2 must be removed from the SNG, which produces a relatively pure CO_2 stream that is naturally ready for sequestration. Combustion of natural gas as with Copano's project, produces an exhaust stream that is less than 10% CO_2, which is far from pure CO_2. Thus, while the Indiana Gasification product will naturally produce a CO_2 byproduct that is amenable to sequestration or use in enhanced oil recovery without further processing, the Copano turbines will not. Separation (purification) of the CO_2 from the turbine combustion exhaust streams requires additional costly steps not otherwise necessary to the process. As a final point, the viability of the Indiana Gasification Project is highly dependent on a 30-year contract requiring the State of Indiana to purchase the SNG produced and federal loan guarantees should the plant fail. In contrast, Copano's project relies on market conditions for viability and is not guaranteed by the government.

The CO_2 streams included in this permit application are similar in nature to the gas-fired industrial boiler in the EPA Guidance Appendix F example and are dilute streams, and thus are not among the facility types for which the EPA guidance states CCS should be listed in Step 1.

The inference from the above citation is that for other types of facilities, CCS does not need to be listed as an available option in Step 1. However, for completeness purposes, Copano has assumed that CCS is a viable control option.

6.1.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technologies that were considered for controlling GHG emissions from the proposed turbines in order of most effective to least effective include:

- CO_2 capture and storage,
- Waste heat recovery,
- Instrumentation and control system, and
- Periodic maintenance and tune-ups.

CO_2 capture and storage is capable of achieving 90% reduction of produced CO_2 emissions and thus is considered to be the most effective control method.

Exhaust waste heat recovery systems are capable of producing about 43 MMBtu/hr of process heat from each turbine. The required heat duty for the process which would utilize the recovered heat ranges from about 40 MMBtu/hr to 65 MMbut/hr. Based on an 80% efficient process heater, this equates to a heat input range of about 50 MMBtu/hr to 80 MMBtu/hr. Supplying this heat with waste heat recovery systems is equivalent to an overall reduction in fuel combustion of between 18% and 26% compared to the combined firing rate of the two turbines and a heater that would otherwise be required.

An instrumentation and control package to continuously monitoring of the turbine package ensures the turbine is operating in the most efficient manner. Instrumentation and controls include:

- Gas flow rate monitoring,
- Fuel gas flow and usage,
- Exhaust gas temperature monitoring,
- Pressure monitoring around the turbine package,
- Temperature monitoring around the turbine package,
- Engine temperature monitoring,
- Vibration monitoring,
- Air/fuel ratio monitoring,

- Waste Heat Recovery Unit temperature and pressure monitoring, and
- Third party quarterly stack testing to ensure emissions are in compliance.

Currently, periodic maintenance and tune-ups of existing turbines are performed per the manufacturer's recommended program. This program is consists thorough inspection and maintenance of all turbine components on a daily, monthly, semi-annual, or annual frequency depending on the parameter or component and as recommended by Solar. The effectiveness of this control option cannot be directly quantified, and is therefore ranked as the least effective alternative.

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

A brief evaluation of each technically feasible combustion turbine control option follows.

CCS. The technology to capture and store CO_2 in permanent underground storage facilities exists and has been used in limited applications, but as stated previously, is not economically viable for most commercial applications. However, since the technology has been demonstrated on some processes and is potentially feasible for the proposed turbines, it cannot be completely ruled out based only on technical infeasibility; therefore, a cost effective analysis was performed for this option. The results of the analysis, presented in Table 6-1, show that the cost of CCS for the project would be approximately $104 per ton of CO_2 controlled, which is not considered to be cost effective for GHG control. This equates to a total cost of about $12,100,000 per year the two turbines. The estimated total capital cost of the Cryo 3 Project is $145,000,000. Based on a 7% interest rate, and 20 year equipment life, this cost equates to an annualized cost of about $13,700,000 for the project alone. Thus, the annualized cost of CCS would almost double the cost of the project; therefore, CCS would make the project economically unviable and is rejected as a control option on the basis of excessive cost.

There are additional negative impacts associated with use of CCS. The additional process equipment required to separate, cool, and compress the CO_2 would require a significant additional power and energy expenditure. This equipment would include amine units, cryogenic units, dehydration units, and compression facilities. The power and energy must be provided from additional combustion units, including heaters, engines, and/or combustion turbines. Electric driven compressors could be used to partially eliminate additional emissions from the HCP, but significant additional GHG emissions, as well as additional criteria pollutant (NO_x, CO, VOC, PM, SO_2) emissions, would occur from the associated power plant that produces the electricity. The additional GHG emissions resulting from additional fuel combustion would either further increase the cost of the CCS system if the emissions were also captured for sequestration or reduce the net amount GHG emission reduction, making CCS even less cost effective than shown in Table 6-1.

Based on both the excessive cost effectiveness in $/ton of GHG emissions controlled and the inability of the project to bear the high cost and the associated negative environmental and energy impacts, CCS is rejected as a control option for the proposed project.

Instrumentation and Controls. Instrumentation and controls that can be applied to the combustion turbines are identified in Section 6.1.3 and are considered an effective means of control for the proposed turbine configuration.

Waste Heat Recovery. Heat recovery systems designed to recover and utilize the waste heat in the turbine exhaust is capable of eliminating about 40 MMBtu/hr of fired heater capacity that would otherwise be required for the process. This corresponds to up to about 21,000 tpy of GHG emissions reductions (estimated GHG emissions from a natural gas fired heater operated 8,760 hr/yr).

Periodic Maintenance and Tune-ups. Periodic maintenance and tune-ups of the turbines include:

- Preventive maintenance check of fuel gas flow meters annually,
- Cleaning of combustors on an as-needed basis, and
- Implementation of manufacturer's recommended inspection and maintenance program.

These activities insure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement.

6.1.5 Step 5 – Selection of BACT

As previously stated, air/fuel controls and efficient combustion turbine design, waste heat recovery, and tune-ups performed as needed are currently utilized on the existing turbines at the HCP to maximize efficiency and thus reduce GHG emissions. These control practices are also included in the design of the new turbines and are thus part of the selected BACT. The following additional BACT practices are proposed for the turbines:

- Determine CO_2e emissions from the turbines based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance,
- Good turbine design to maximize efficiency,

- Install and operate a Waste Heat Recovery Unit (WHRU) with a capacity of about 43 MMBtu/hr on each turbine to recovery heat from the turbine exhaust. These systems will eliminate the need for a fired stand alone heat medium heater and will provide sufficient heat for the Inlet Gas Heater, Regeneration Gas Heater, Amine Reboiler, and Trim Reboiler.
- instrumentation and control package including:
  - Gas flow rate monitoring,
  - Fuel gas flow and usage,
  - Exhaust gas temperature monitoring,
  - Pressure monitoring around the turbine package,
  - Temperature monitoring around the turbine package,
  - Engine temperature monitoring,
  - Vibration monitoring,
  - Air/fuel ratio monitoring,
  - Waste Heat Recovery Unit temperature and pressure monitoring, and
  - Third party quarterly stack testing to ensure emissions are in compliance.
- Implement Solar's recommended comprehensive inspection and maintenance program for the turbines,
- Clean combustors as needed,
- Calibrate and perform preventive maintenance on the fuel flow meter once per year, and
- Maintain a minimum combustion turbine/WHRU thermal efficiency of 40%, on a 12-month rolling average basis. This is equivalent to 0.84 lb of CO_2e per hp-hr. The monitoring computer system will automatically calculate efficiency for each hour of operation using monitored firing rate, turbine output in hp-hr, and flow and temperature on the hot oil system that uses the heat recovered by the WHRU. An alarm will alert the operator when the 12-month average efficiency drops below a predetermined set point that could result in non-compliance with the proposed limit.

6.2 Heaters

6.2.1 Step 1 – Identification of Potential Control Technologies

The potentially applicable technologies to minimize GHG emissions from the heaters include the following:

- Periodic Tune-up – Periodically tune-up of the heaters to maintain optimal thermal efficiency.
- Heater Design – Good heater design to maximize thermal efficiency,

- Heater Air/Fuel Control – Monitoring of oxygen concentration in the flue gas to be used to control air to fuel ratio on a continuous basis for optimal efficiency.

- Waste Heat Recovery – Use of heat recovery from the heater exhausts to preheat the heater combustion air or process streams in the unit.

- Use of Low Carbon Fuels – Fuels vary in the amount of carbon per btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. Selecting low carbon fuels is a viable method of reducing GHG emissions.

- CO_2 Capture and Storage – Capture and compression, transport, and geologic storage of the CO_2.

6.2.2 Step 2 – Elimination of Technically Infeasible Alternatives

The proposed heaters are small (25 MMBtu/hr each) and will only be operated up to 600 hours year each. As a result, each heater will emit less than 900 tpy of CO_2e, which is about 0.5% of the total project CO_2e emissions. Waste heat recovery is not applicable to intermittently operated combustion units, and is therefore rejected for the heaters. Carbon capture and storage is also not a practical or economically feasible add-on option for very small intermittent sources, and was also eliminated. Automated air/fuel controls would not result in any appreciable increase in heater efficiency or resulting GHG emission reduction due to the already insignificant amount of GHG emissions from the heaters, and was therefore also rejected as a viable control options. The remaining control options identified in Step 1 have a minor degree of applicability and have therefore been retained for further consideration, although the potential for any significant emission reduction does not exist due to the already low emission rates.

6.2.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technologies applicable to the proposed heater design in order of most effective to least effective include:

- Use of low carbon fuels (up to 100% for fuels containing no carbon),
- Heater Design (up to 10%), and
- Periodic tune-up (up to 10% for boilers; information not found for heaters).

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel to CO_2. Fuels used in industrial process and power generation typically include coal, fuel oil, natural gas, and process fuel gas. Of these, natural gas is typically the lowest carbon fuel that can be burned, with a CO_2 emission factor in lb/MMBtu about 55% of that of subbituminous coal. Process fuel gas is a byproduct of chemical process, that typically contains a higher fraction of longer chain carbon compounds than natural gas and thus results in more CO_2 emissions. Table C-2 in 40 CFR Part 98 Subpart C, which contains CO_2 emission factors for a variety of fuels, gives a CO_2 factor of 59 kg/MMBtu for fuel gas compared to 53.02 kg/MMBtu for natural gas. Of over 50 fuels identified in Table C-2, coke oven gas, with a CO_2 factor of 46.85 kg/MMBtu, is the only fuel with a lower CO_2 factor than natural gas, and is not viable fuel for the proposed heaters as the HCP does not contain coke ovens. Although Table C-2 includes a typical CO_2 factor of 59 kg/MMBtu for fuel gas, fuel gas composition is highly dependent on the process from which the gas is produced. Some processes produce significant quantities of hydrogen, which produces no CO_2 emissions when burned. Thus, use of a completely carbon-free fuel such as 100% hydrogen, has the potential of reducing CO_2 emissions by 100%. Hydrogen fuel, in any concentration, is not a readily available fuel for most industrial facilities and is only a viable low carbon fuel at industrial plants that generate hydrogen internally. Hydrogen is not produced from the processes at the HCP, and is therefore not a viable fuel. Natural gas is the lowest carbon fuel available for use in the proposed heaters.

Good heater design and periodic tune-ups have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. The estimated efficiencies were obtained from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008). This report addressed improvements to existing energy systems as well as new equipment; thus, the higher end of the range of stated efficiency improvements that can be realized is assumed to apply to the existing (older) facilities, with the lower end of the range being more applicable to new heater designs.

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

Use of Low Carbon (Natural Gas) Fuel. Natural gas is the lowest carbon fuel available for use in the proposed heaters. Natural gas is readily available at the HCP and is currently considered a very cost effective fuel alternative. Natural gas is also a very clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels. Natural gas is the fuel of choice for most industrial facilities, especially natural gas processing facilities, in addition to being the lowest carbon fuel available. Although use of natural gas as fuel results in about 28% less CO_2 emissions than diesel fuel and 45% less CO_2 emissions than subbituminous coal; it is more prudent to consider natural gas to be the “baseline” fuel for this BACT analysis; thus, claiming an emission reduction from its use would be a misrepresentation.

Heater Design. New heaters can be designed with efficient burners and state-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency. Due to the very low energy consumption of these small intermittently used heaters, only basic heater efficiency features are practical for consideration in the heater design.

Periodic Heater Tune-ups. Periodic tune-ups of the heaters include:

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

These activities insure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement, although convection cleaning has shown improvements in the 0.5 to 1.5% range. Due to the minimal use of these heaters, regularly scheduled tune-ups and inspections are not warranted.

6.2.5 Step 5 – Selection of BACT

Efficient heater design, use of natural gas, and tune-ups performed as needed are proposed as BACT for the heaters as detailed below.

- Use of low carbon fuel (natural gas). Natural gas will be the only fuel fired in the proposed heaters. It is the lowest carbon fuel available for use at the HCP.
- Good heater design and operation to maximize thermal efficiency and reduce heat loss to the extent practical for heaters of this size in intermittent service
- Use of manual air/fuel controls to maximize combustion efficiency.
- Clean and inspect heater burner tips and perform tune-ups as needed and per vendor recommendations.

6.3 RTO

The acid gas stream from the amine treating unit, consisting primarily of CO_2, contains VOCs and H_2S that must be controlled prior to venting the stream to the atmosphere. Copano proposes to use a regenerative thermal oxidizer (RTO) to control this stream. The advantages of an RTO are that it has a high destruction efficiency and it requires no supplemental natural gas to combust the waste stream. The BACT analysis looked at other options to the RTO.

6.3.1 Step 1 – Identification of Potential Control Technologies

The options considered for controlling the acid gas stream include:

- Use of a well designed RTO,
- Instrumentation and controls to ensure efficient operation of RTO,
- Inspection and maintenance of RTO,
- Use of a flare, and
- Carbon capture and sequestration.

6.3.2 Step 2 – Elimination of Technically Infeasible Alternatives

All of the identified control options are considered to be technically feasible.

6.3.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The control options are ranked from most effective to least effective as follows:

- Carbon capture and sequestration,
- Use of an RTO including instrumentation and control packate and manufacturer's inspection and maintenance program, and
- Use of a flare.

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

Carbon Capture and Sequestration (CCS). The viability of CCS has been discussed previously in Section 6.1 and is not considered a viable option at this time. However, for completeness, a cost analysis for CCS applied to acid gas stream was conducted and is presented in Table 6-2. The total estimated capital cost of CCS applied to this stream only is $50,000,000. This cost is over one-third of the $145,000,000 cost of the proposed project and would thus make the project economically unviable. In addition, the cost effectivenss of this control option is estimated to be $89 per ton of CO_2e controlled, which is also considered to be an excessive cost for GHG emission control. Based on these excessive costsm CCS was rejected from further consideration as a control option for this stream.

Use of an RTO. A well designed RTO is a proven technology to treat streams such as the amine unit acid gas stream. Copano currently utilizes this technology on similar units at the HCP, and it has proven to be a successful and fuel efficient control option with no significant negative environmental or energy impacts. The RTO is capable of achieving 99% destruction of VOCs and 99.8% destruction of H_2S. Use of an RTO eliminates the need for supplemental natural gas to maintain proper combustion. The only expected natural gas usage is for the pilot, which will have an annual average firing rate of about 1 MMBtu/hr, which results in a very minimal 512 tpy of CO_2e emissions.

Use of a flare. Due to the low heat content of the acid gas stream, use of a flare would require significant supplemental natural gas to maintain complete combustion. An estimated 55 MMBtu/hr of natural gas would be required to maintain proper combustion. Combustion of this amount of natural gas would result in an additional 29,000 tpy of CO_2e emissions to the atmosphere. The maximum destruction efficiency that could be achieved with a flare is 98% for both VOC and H_2S compared to 99% for VOC and 99.8% for H_2S with the use of an RTO.

Because a flare would be a less effective means of control and would result in more GHG emissions than an RTO, it was rejected from consideration.

6.3.5 Step 5 – Selection of BACT

Copano proposes to utilize a well designed and operated RTO to treat the amine unit acid gas stream. Natural gas is only required for the pilot, which will produce a negligible 512 tons of GHG emissions as CO_2e. Therefore, an RTO produces no significant additional GHG emissions beyond what is already present in the acid gas stream. The design and operation of the RTO will include the following:

- instrumentation and control package including:
  - Acid gas vent stream flow rate monitoring,
  - Fuel gas flow and usage,
  - RTO temperature monitoring, and
  - Pressure monitoring around the RTO package;
- Implement vendor’s recommended comprehensive inspection and maintenance program for the RTO;
- Clean RTO as needed; and
- Calibrate and perform preventive maintenance on RTO instruments and control package once per year.

6.4 Process Fugitives

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The additional methane emissions from processes fugitives have been conservatively estimated to be 357 tpy as CO_2e. This is a negligible contribution to the total GHG emissions; however, for completeness, they are addressed in this BACT analysis.

6.4.1 Step 1 – Identification of Potential Control Technologies

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

6.4.2 Step 2 – Elimination of Technically Infeasible Alternatives

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

6.4.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

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

Although technically feasible, use of an LDAR program to control the negligible amount of GHG emissions that occur as process fugitives is clearly cost prohibitive. Table 6-3 presents a cost analysis for a basic LDAR program that results in a cost effectiveness of $161/ton of CO_2e controlled. The cost analysis demonstrates that an LDAR program is not cost effective for GHG emissions; however, if an LDAR program is being implemented for VOC control purposes, it will also result in effective control of the small amount of GHG emissions from the same piping components. Copano uses TCEQ's 28M LDAR program at the HCP to minimize process fugitive VOC emissions at the plant, and this program has also been proposed for the additional fugitive VOC emissions associated with the project.

6.4.5 Step 5 – Selection of BACT

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

Table 6-1

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

CCS System Component	Cost ($/ton of CO_2 Controlled)[1]	Tons of CO_2 Controlled per Year[2]	Total Annualized Cost
CO_2 Capture and Compression Facilities	$103	117,174	$12,068,942
CO_2 Transport Facilities[3]	Not Included	Not Included	Not Included
CO_2 Storage Facilities	$0.51	117,174	$59,759
Total CCS System Cost	$104	117,174	$12,128,701

Proposed Plant Cost	Total Capital Cost	Capital Recovery Factor[4]	Annualized Capital Cost
Cost of CRYO3 Plant without CCS[5]	$145,000,000	0.0944	$13,686,974

1. Costs are from *Report of the Interagency Task Force on Carbon Capture (August, 2010)* . A range of costs was provided for transport and storage facilities; for conservatism, the low ends of these ranges were used in this analysis as they contribute little to the total cost. Reported costs in $/tonne were converted to $/ton.

2. Tons of CO_2 controlled assumes 90% capture of all CO_2 emissions from the two turbines.

3. Pipeline costs are included in Table 6-2 for Acid Gas Stream, and it is assumed that the pipeline can handle both the turbine CO_2 and Acid Gas CO_2 streams.

4. Capital recovery factor based on 7% interest rate and 20 year equipment life.

Interest rate	7%
Equipent Life (yrs)	20

Table 6-2
Approximate Cost for Construction and Operation of a CCS System for Acid Gas Stream

Description	Cost	Basis
Capital Cost:		
AGI Compressor - Primary	$3,000,000	2.7 mmscfd, 7 psig to 2000 psig, 1000 hp, electric compression
AGI Compressor - Back Up	$3,000,000	2.7 mmscfd, 7 psig to 2000 psig, 1000 hp, electric compression
Installation- Compression	$4,000,000	Assume $2000/hp (includes power upgrade)
Dehydration Unit	$1,000,000	Past project cost for similar facility
AGI Pipeline - 6" Diameter	$29,000,000	50-mile pipeline 6 inch diameter (50 miles is location of nearest storage cavern). DOE/NETL calculation method (see below).
AGI Well (permitting, drilling, completion, etc.)	$10,000,000	Industry estimate
Total Capital Cost for Acid Gas Compression, Pipeline, and Well	**$50,000,000**	
Capital Recovery Factor[1]	0.0944	7% interest rate and 20 year equipment life
Annualized Capital Cost ($/yr)	**$4,719,646**	Total capital cost times capital recovery factor
Operating Cost:		
Power Cost, $/year	$489,925	1000 hp electric compressor and $0.075/kwh electricity cost
O&M Cost, $/year	$1,000,000	Past O&M estimate
Total Annual Operating Cost ($/yr)	**$1,489,925**	
Total Cost:		
Total Annual Cost ($/yr)	**$6,209,571**	Annualized capital cost plus annual operating cost
GHG Emissions Controlled (ton/yr)	69,459	From GHG Calculations in Appendix A
Cost Effectiveness ($/ton)	**$89**	Total Annual Cost/GHG Emissions Controlled

1. Capital recovery factor based on 7% interest rate and 20 year equipment life.

Interest rate:	7%
Equipent Life (yrs):	20

Capital Cost for Construction of CO2 Pipeline to Nearest Storage Cavern (Markham, TX area):

Length in miles (L):	50
Diameter in inches (D):	6

Component	**Cost**	**Cost Equation**[2]
Materials	$4,040,116	Materials = $64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D + 26,960)
Labor	$18,361,756	Labor = $341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)
Miscellaneous	$4,711,310	Misc. = $150,166 + $1.58 x L x (8,417 x D + 7,234)
Right-of-Way	$2,043,037	Right-of-Way = $48,037 + $1.20 x L x (577 x D + 29,788)
Total Cost of Pipeline	**$29,156,218**	

2: Pipeline cost equations are from: *Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs* , National Energy Technology Laboratory, U.S. Dept. of Energy, DOE/NETL-2010/1447, March 2010.

Table 6-3 Cost Effectiveness of 28M LDAR Program for Process Fugitives

Monitoring Cost:	$1.45	per component per quarter
Number of Valves:	1,720	monitored
Number of Flanges:	4,300	not monitored
Number of PRVs:	24	monitored
Number of Pumps:	8	monitored
Number of Comps:	14	monitored
Total Number Monitored:	1,766	monitored
Total Cost of Monitoring:	$10,243	per year
Number of Repairs:	848	per year (12% of monitored components per quarter)
Cost of Repairs:	$144,106	per year @ $200 per component (85% of leaking components; remaining 15% only require minor repair)
Cost to re-monitor repairs:	$1,229	per year
Total Cost of LDAR:	$155,578	per year (montoring + repair + re-monitor)
Emission Reduction:	45.98	tpy of methane (based on 28M reduction credits)
Emission Reduction:	965.66	tpy of CO_2e
Cost Effectiveness:	$3,383	per ton of CH_4
Cost Effectiveness:	**$161**	per ton of CO_2e

Section 7
Additional Impact Analysis

PSD regulations require an Additional Impacts Analysis for projects that are subject to PSD review. In 40 CFR 52.21(o), it states that:

> (1) The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.
>
> (2) The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.

This section of the application addresses these requirements.

7.1 Visibility, Soils, and Vegetation

The proposed project will not result in a significant increase in any air contaminant other than GHGs; therefore, the project is not subject to PSD review for any other pollutant. GHGs themselves are not known to have any direct impact on visibility, soils, and vegetation other than their possible impact associated with global warming, which EPA has ruled does not need to be evaluated for GHG PSD permits. However, emissions of other air pollutants from the project could potentially impact these resources. Because the project increases for all other pollutants are insignificant, it is concluded that their impact on visibility, soils, and vegetation is also insignificant.

7.2 Associated Growth

The proposed project will not significantly affect residential, commercial, or industrial growth in the area. Only 2 to 3 new jobs are expected to be created by the addition of the proposed Cryo 3 facilities at the HCP. Even if these jobs were to be filled by individuals relocating to the area, it would result in a negligible impact on the existing infrastructure. Because these impacts will be negligible, the corresponding impact on air quality will also be negligible.

Appendix A

Emissions Calculations

Table A-1
Greenhouse Gas (GHG) Emissions from New Cryogenic Plant
Copano Gas Processing, LP, Houston Central Gas Plant
Colorado County, Texas

EPN	Description	Firing Rate (mmbtu/hr) HHV	Firing Rate (mmbtu/yr) HHV	CO2 (tpy*)	CH4 (tpy*)	N2O (tpy*)	Total CO2 Equivalent (tpy*)
HTR-3	Supplemental Gas Heater	25.00	15,000.0	875.9	0.02	0.002	876.7
HTR-4	Supplemental Gas Heater	25.00	15,000.0	875.9	0.02	0.002	876.7
RTO-3	RTO - Natural Gas Combustion	1.00	8,760.0	511.5	0.01	0.001	512.0
	RTO - Waste Gas Combustion			68,940.5	0.3		68,946.7
TURB-5	Solar Mars 100	127.14	1,113,729.9	65,033.0	1.2	0.1	65,096.8
TURB-6	Solar Mars 100	127.14	1,113,729.9	65,033.0	1.2	0.1	65,096.8
CRYO3 FUG	Fugitives	NA	NA	0.0	22.1	0.0	465.0
Total				**201,269.7**	**24.9**	**0.2**	**201,870.7**
Contemporaneous Changes							
TURB-3	Solar Mars 100			58,819.1	1.1	0.1	58,876.7
TURB-4	Solar Mars 100			58,819.1	1.1	0.1	58,876.7
HTR-1	Supplement Gas Heater			875.9	0.0	0.0	876.7
HTR-2	Supplement Gas Heater			875.9	0.0	0.0	876.7
RTO-2	Regenerative Termal Oxidizer			58,005.3	0.2	0.002	58,009.5
STKBLR3	Steam Boiler No. 3			110,487.1	2.1	0.2	110,595.5
CRYO2 FUG	Fugitives			0.0	22.1	0.0	465.0

* Note all emission rates are in units of short tons.

** These two turbines will have a combined operating rate equal to one turbine operating at capacity year round.

Turbine Operating Schedule: 8760 hrs/yr
Heater Operating Schedule: 600 hrs/yr

Emission Rate (tpy) = Emission Factor (lb/mmbtu) x Firing Rate (mmbtu/yr) / 2000 lb/ton

Emission Factors:

Emission Factors from Tables C-1 & C-2 of Appendix A to 40 CFR Part 98 Subpart C

Pollutant	kg/mmBtu	lb/mmbtu, hhv
CO2	53.02	116.78
CH4	0.001	0.0022
N2O	0.0001	0.00022

Factors are for natural gas

CO2 Equivalents (ton/ton):

CO2	1.0
CH4	21.0
N2O	310.0

Proposed Turbine/WHRU Efficiency Limit:

40% proposed annual average limit to reflect reduced load, site conditions, & degredation
2545 btu/hp-hr (published constant)
6,443 btu/hp-hr, LHV @ 25% efficiency
7,149 btu/hp-hr, HHV @ 25% efficiency
116.90 lb CO2e/mmbtu (sum of CO2, CH4, N2O emission factors)
0.84 lb CO_2e/hp-hr

Table A-2
Regenerative Thermal Oxidizer Emissions
Copano Gas Processing, LP, Houston Central Gas Plant
Colorado County, Texas

Emission Source Type:	Regenerative Thermal Oxidizer
EPN:	RTO-3
Firing Rate (MMBtu/hr):	2.5
Operating Hours (hrs/yr):	8760
Waste Gas Flow from Cryo Unit 3 (scf/hr):	149,275
scf/mole:	387

Natural Gas Emissions (startup)

Short term Rate

Firing Rate (MMBtu/hr)	Fuel Heating Value (Btu/scf)	Hours of Operation (hrs/year)
3.2	1020	8760

Annual Average Rate

Firing Rate (MMBtu/hr)	Fuel Heating Value (Btu/scf)	Hours of Operation (hrs/year)
1	1020	8760

Cryo Unit #3 (NEW) - Amine Still Flux Accumulator Acid Gas Analysis

Waste Stream								
Component	Inlet Flow to RTO						Outlet CO_2 to Atmos.	
	MW	Wt %	Mol%	Vol%	tpy	MMscf/yr	Carbon #	tpy
Methane	16.04	0.04%	0.1090%	0.1090%	29.54	1.4	1	81.0
Ethane	30.07	0.03%	0.0462%	0.0462%	23.45	0.6	2	68.7
Isobutane	58.12	0.00%	0.0000%	0.0000%	-	0.0	4	0.0
n-Butane	58.12	0.05%	0.0378%	0.0378%	37.11	0.5	4	112.4
Isopentane	72.15	0.00%	0.0000%	0.0000%	-	0.0	5	0.0
n-Pentane	72.15	0.02%	0.0118%	0.0118%	14.36	0.2	5	43.8
Carbon Dioxide	44.01	96.41%	91.9500%	91.9500%	68,388	1,202.4	1	68,388.1
Nitrogen	28.01	0.00%	0.0000%	0.0000%	-	0.0	0	0.0
H2S	34.08	0.00%	0.0001%	0.0001%	0.06	0.0	0	0.0
Propane	44.10	0.05%	0.0502%	0.0502%	37.39	0.7	3	111.9
C6+	86.18	0.06%	0.0302%	0.0302%	43.91	0.4	6	134.5
Water	18.00	3.33%	7.7688%	7.7688%	2,363.22	101.6	0	0.0
TOTAL		100.00%	100.00%	100.00%	70,937	1,308	NA	68,940

Example Calculations:

Methane (MMscf/yr) = 0.109% vol x 149,275 scf/hr x 8760 hr/yr / 1,000,000 scf/MMscf = 1.4 MMscf/yr

CO2 (tpy) = 1.4 MMscf/yr x 1 Carbon per mole x 44.01 lb/mole x 1 mole/387 scf x 1,000,000 scf/MMscf x 1 ton/2000 lb = 81.0 tpy

Methane Emissions (from undestructed methane in acid gas):

Component	Inlet Flow to RTO						Outlet CH_4 to Atmos.	
	MW	Wt %	Mol%	Vol%	tpy		DRE	tpy
Methane	16.04	0.04%	0.1090%	0.1090%	29.54		99%	0.3

Note: Gas flow rate and composition used for GHG emissions differs from the worst case used for other compounds in the TCEQ permit, as the above scenario results in higher GHG emissions.

Table A-3
Cryogenic Plant Equipment Leak Fugitives (EPN: CRYO3 FUG)
Copano Gas Processing, LP, Houston Central Gas Plant
Colorado County, Texas

Monitored Component Type	Service	[1]Oil & Gas Production Operations Fugitive Emission Factors	Total Component Count	28M Control Efficiencies (%)	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (TPY)	Controlled Emissions (lb/hr)	Controlled Emissions, all compounds (TPY)
Valves	Gas/Vapor	0.00992	1600	75%	15.87	69.52	3.97	17.38
	Light Liquid	0.0055	120	75%	0.66	2.89	0.17	0.72
	Heavy Liquid	0.0000185		0%				
Pumps	Gas Vapor	0.00529						
	Light Liquid	0.02866	14	75%	0.40	1.76	0.10	0.44
	Heavy Liquid	0.00113		0%				
Flanges	Gas/Vapor	0.00086	4000	30%	3.44	15.07	2.41	10.55
	Light Liquid	0.000243	300	30%	0.07	0.32	0.05	0.22
	Heavy Liquid	0.00000086		30%				
Compressors	Gas/Vapor	0.0194	8	75%	0.16	0.68	0.04	0.17
Relief Valves	Gas/Vapor	0.0194	24	75%	0.47	2.04	0.12	0.51
		Total:	***6066***		***21.07***	***92.27***	***6.85***	***29.99***

1) Emission factors are from TCEQ Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives October 2000 which refers to Oil and Gas Production Operations extracted from Table 2-4 of EPA-453/R-95-017

2) For Oil and Gas Production Operations, "Other" includes diaphragms, dump arms, hatches, instruments, meters, polished rods, and vents.

Sample Calculations:
Non-Monitored Component Count Emissions (lb/hr)=Emission Factor (lb/hr) * Non-Monitored Component Count

Speciated Emissions for Methane Calculation:

Inlet Gas Analysis					**Component Emissions**	
Compound	**Dry Basis Mole %**	**MW**	**lb/mol**	**Dry Basis Weight %**	**lb/hr**	**TPY**
Methane	87.40	16.043	1402.21	73.83%	5.06	22.14
Ethane	6.40	30.070	192.39	10.13%	0.69	3.04
Propane	2.54	44.097	111.79	5.89%	0.40	1.77
i-butane	0.497	58.124	28.89	1.52%	0.10	0.46
n-butane	0.66	58.124	38.25	2.01%	0.14	0.60
i-pentane	0.22	72.151	15.51	0.82%	0.06	0.24
n-pentane	0.15	72.151	10.82	0.57%	0.04	0.17
$C6^+$	0.17	86.117	14.64	0.77%	0.05	0.23
CO2	1.84	44.010	80.85	4.26%		
N2	0.14	28.013	3.84	0.20%		
H2S	0.00	34.076	0.00	0.00%	0.00	0.00
Total:	100.00		1899.17	100.0%		
			Methane Total:	73.83%	5.06	**22.14**

**Use of inlet gas analysis is conservative as the compressors will be compressing residue gas.*

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