Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Copano Processing, L.P., Houston Central Gas Plant

Permit Number: PSD-TX-104949-GHG

December 2012

This document serves as the Statement of Basis (SOB) for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On June 8, 2012, Copano Processing, L.P. (Copano) Houston Central Gas Plant (HCP), submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a proposed construction project. On August 6, 2012, Copano submitted additional information for inclusion into the application. In connection with the same proposed construction project, Copano submitted an application for a Non-Rule Oil and Gas Standard Permit for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on May 16, 2012. The project at the HCP proposes to construct a new 400 MMSCF/day cryogenic process train (Cryogenic 3 Process Unit). This train will consist of inlet gas mole sieve dehydrators, two supplemental heaters, a cryogenic process unit, a liquid amine treating unit controlled by a Regenerative Thermal Oxidizer (RTO), two residue turbines, an amine storage tank, and associated fugitive components. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the Copano, Houston Central Gas Plant.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that Copano's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by Copano, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

Applicant

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II. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305). The State of Texas still retains approval of its plan and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Aimee Wilson
Air Permitting Section (6PD-R)
(214) 665-7596

The Non-GHG PSD Permitting Authority for the State of Texas is:

Air Permits Division (MC-163)
TCEQ
P.O. Box 13087
Austin, TX 78711-3087

III. Facility Location

The Copano, Houston Central Gas Plant is located in Colorado County, Texas, and this area is currently designated "attainment" for all criteria pollutants. The nearest Class 1 area is the Big Bend National Park, which is located well over 100 miles from the site. The geographic coordinates for this facility are as follows:

Latitude: 29º 28' 12" North
Longitude: -96º 37' 28" West

Below, Figure 1 illustrates the facility location for this draft permit.

Figure 1. Copano Processing, L.P., Houston Central Gas Plant Location

IV. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes Copano's application is subject to PSD review for the pollutant GHGs, because the project would lead to an emissions increase of GHGs for a facility as described at 40 CFR § 52.21(b)(49)(v). Under the project, the source is an existing minor source for PSD and the modification alone exceeds the threshold of 100,000 tpy CO_2e (equals or exceeds 100/250 TPY GHG mass basis). Copano calculates CO_2e emissions of 201,871 tpy CO_2e. EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

As the permitting authority for regulated NSR pollutants other than GHGs, TCEQ has determined the proposed project is not subject to PSD review for non-GHG pollutants. TCEQ has determined that the proposed project is eligible to utilize the Non-Rule Oil & Gas Standard Permit. TCEQ issued the standard permit for the non-GHG pollutants on August 20, 2012. Under the limits of the minor NSR permit, there will not be net significant increases of regulated NSR pollutants other than GHGs in conjunction with the project.

Accordingly, under the circumstances of this project, the TCEQ has issued a permit for the non-GHG portion of the project and EPA will issue a PSD Permit for the GHG portion of the project.[1]

EPA Region 6 applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with that guidance, we have neither required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. The applicant submitted an analysis to meet the requirements of 40 CFR § 52.21(o), as it may otherwise apply to the project. We note again, however, that the project has regulated NSR pollutants that are non-GHG pollutants, which are addressed by the standard permit issued by TCEQ.

V. Project Description

The proposed GHG PSD permit, if finalized, will allow Copano to construct a new 400 million standard cubic feet per day (MMSCFD) cryogenic process train (Cryogenic 3 Process Unit). This will increase the total plant capacity to 1.5 billion standard cubic feet per day (BSCFD) from 1,100 MMSCFD. This train will consist of inlet gas mole sieve dehydrators, two supplemental

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf.

heaters, a cryogenic process unit, a liquid amine treating unit controlled by a Regenerative Thermal Oxidizer (RTO), two residue turbines, an amine storage tank, and associated fugitive components.

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 pass 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 via pipeline. The compressors, used to compress the residue gas sent to pipeline, are driven by two new gas-fired combustion turbines. The NGL liquids will be treated in a liquid amine treating unit (LL Treater), where most of the 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) from the amine treating unit will then be routed to a new regenerative thermal oxidizer. A small vent stream from the LL Treater will be routed into the plant fuel gas system. This minor addition to the fuel gas system will replace a small amount of existing fuel (about 1.5 MMBtu/hr) and therefore will not result in any increase in CO_2e emissions.

New project air emission sources consist of two supplemental gas-fired heaters (HTR-3 and HTR-4), acid gas from an amine treating unit controlled by a new Regenerative Thermal Oxidizer (RTO-3), an amine storage tank (TANK-3), two Solar Mars 100 combustion turbines (TURB-5 and TURB-6) used for compression of the residue gas, and fugitive piping components (CRYO3 FUG).

VI. General Format of the BACT Analysis

The BACT analyses was conducted in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, which outlines the steps for conducting a top-down BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;

(2) Eliminate technically infeasible control options;

(3) Rank remaining control technologies;

(4) Evaluate the most effective controls and document the results; and

(5) Select BACT.

Also in accordance with the top-down BACT guidance, the BACT analyses also take into account the energy, environmental, and economic impacts of the control options during step 4. Emission reductions may be determined through the application of available control techniques, process design, and/or operational limitations. Such reductions are necessary to demonstrate that the emissions remaining after application of BACT will not cause adverse environmental effects to public health and the environment.

Each of the emission units addressed in the PSD GHG application was evaluated separately in the top-down 5-step BACT analysis.

VII. Applicable Emission Units and BACT Discussion

The majority of the contribution of GHGs associated with the project is from emissions at combustion sources (i.e., combustion turbines, heaters, and regenerative thermal oxidizer). Stationary combustion sources primarily emit CO_2, and small amounts of N_2O and CH_4. The site has some fugitive emissions from piping components which contribute relatively small amount of GHGs. Stationary combustion sources primarily emit CO_2, and small amounts of N_2O and CH_4. The following devices are subject to this GHG PSD permit:

- Combustion Turbines (TURB-5 and TURB-6)
- Heaters (HTR-43 and HTR-4)
- Regenerative Thermal Oxidizer (RTO-3)
- Process Fugitives (CRYO3 FUG)

VIII. Combustion Turbines (TURB-5 and TURB-6)

There will be two new natural gas fired combustion turbines (TURB-5 and TURB-6) used for residue gas compression into a natural gas pipeline for sale. The compressor turbines are Solar Mars 100 combustion turbines. Each has a nominal rated capacity of 15,000 HP.

As part of the PSD review, Copano provides in the GHG permit application a 5-step top-down BACT analysis for the combustion turbines. In setting forth BACT for this proposed permit, EPA has reviewed Copano's BACT analysis for the combustion turbines, portions of which has been incorporated into this Statement of Basis, and also conducted its own analysis, as summarized below.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Carbon Capture and Storage (CCS)* – CCS is an available add-on control technology that is applicable for all of the sites affected combustion units.

- *Periodic Maintenance and Tune-up* – Periodic tune-up the turbines to maintain optimal thermal efficiency.
- *Turbine Design* – Good turbine design to maximize thermal efficiency.
- *Instrumentation and Controls* – Proper instrumentation ensures efficient turbine operation to minimize fuel consumption.
- *Waste Heat Recovery* – Use of heat recovery from the turbine exhausts to provide process heat for use at the plant.

Carbon Capture and Sequestration (CCS)

Carbon capture and storage is an available GHG control technology for "facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for 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)."[2] For purposes of a BACT analysis, CCS is classified as an add-on pollution control technology. CCS involves the separation and capture of CO_2 from the combustion process flue gas, pressurization of the captured CO_2, and transportation by pipeline or other means of transportation, if necessary, to a site where it is injected into a long-term geological location. Several types of CCS technologies are in various stages of development and are being considered for CO_2 separation and capture.

As it stands currently, CCS Technology and its components can be summarized in the table[3] below adopted from IPCC's *Carbon Dioxide Capture and Storage* report:

CCS Component	CCS Technology
Capture	Post-combustion
	Pre-combustion
	Oxyfuel combustion
	Industrial separation (natural gas processing, ammonia production)
Transportation	Pipeline
	Shipping
Geological Storage	Enhanced Oil Recovery (EOR)
	Gas or oil fields
	Saline formations
	Enhanced Coal Bed Methane Recovery (ECBM)

[2]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011).

[3] Intergovernmental Panel on Climate Change (IPCC) Special Report, Bert Metz, Ogunlade Davidson, Heleen de Coninck, Manuela Loos and Leo Meyer (Eds.), *Carbon Dioxide Capture and Storage* (New York: Cambridge University Press, 2005), Table SPM.2, 8. <http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf>.

CCS Component	CCS Technology
Ocean Storage	Direct injection (dissolution type)
	Direct injection (lake type)
Mineral carbonation	Natural silicate minerals
	Waste minerals
CO_2 Utilization/Application	Industrial Uses of CO_2 (e.g. carbonated products)

For large, point sources, there are three types of CO_2 capture configurations – pre-combustion capture, post-combustion capture, and oxy-combustion capture:

1) Pre-combustion capture is the capture of CO_2 prior to combustion. It is a technological option available to integrated gasification combined cycle (IGCC) plants. In these plants, coal is gasified to form synthesis gas (syngas with key components of carbon monoxide and hydrogen). CO is reacted with steam to form CO_2 which is then removed and the hydrogen is then diluted with nitrogen and fed into the gas turbine combined cycle.

2) Post-combustion capture involves extracting CO_2 in a purified form from the flue gas following combustion of the fuel. This capture technology is primarily for coal-fired power plants and electric generating units (EGU), although it may be of use for other source types. Currently, all commercial post-combustion capture is via chemical absorption process using monoethanolamine (MEA)-based solvents.[4]

3) Oxy-combustion technology is primarily applied to coal-burning power plants where the capture of CO_2 is obtained from a pulverized coal oxy-fuel combustion in which fossil fuels are burned in a mixture of recirculated flue gas and oxygen, rather than in air. The remainder of the flue gas, that is not recirculated, is rich in CO_2 and water vapor, which is treated by condensation of the water vapor to capture the CO_2.[5] Nitrogen is a major component of flue gas in the boiler units that burn coal in air, post-combustion capture of CO_2 is essentially a nitrogen- CO_2separation which can be done but at a high cost. However if there were no nitrogen present as in the case of oxy-combustion, then CO_2 capture from flue gas would be greatly simplified[6]. It is expected that an optimized oxy-combustion power plant will have ultra-low CO_2 emissions.

[4] Wes Hermann et al. *An Assessment of Carbon Capture Technology and Research Opportunities - GCEP Energy Assessment Analysis, Spring 2005*. <http://gcep.stanford.edu/pdfs/assessments/carbon_capture_assessment.pdf>.
[5] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, "Oxy-Fuel Combustion", August 2008. < http://www.netl.doe.gov/publications/factsheets/rd/R&D127.pdf>.
[6] Herzog et al., page 4-5.

Once CO_2 is captured from the flue gas, CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline) into a storage area that, in most cases, is a geological storage area. Also, CO_2 can be stored and transported for a non-storage use (e.g., carbonation for beverages).

Geological storage of CO_2 involves the injection of compressed CO_2 into deep geologic formations (injection zones) overlain by competent sealing formations and geologic traps that will prevent the CO_2 from escaping. There are five types of geologic formations that are considered: clastic formations; carbonate formations; deep, unmineable coal seams; organic-rich shales; and basalt interflow zones. There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[7]

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for this project.

EPA considers CCS to be an available control option for high-purity CO_2 streams that merits initial consideration as part of the BACT review process, especially for new facilities. As noted in EPA's GHG Permitting Guidance, a control technology is "available" if it has a potential for practical application to the emissions unit and the regulated pollutant under evaluation.[8] Thus, even technologies that are in the initial stages of full development and deployment for an industry, such as CCS, can be considered "available" as that term is used for the specific purposes of a BACT analysis under the PSD program. In 2010, the Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of this clean coal technology. As part of its work, the Task Force prepared a report that summarized the state of CCS and identified technical and non-technical challenges to implementation.[9] EPA, which participated in the Interagency Task Force, supported the Task Force's conclusion that although current technologies could be used to capture CO_2 from new and existing plants, they were not ready for widespread implementation at all facility types. This conclusion was based primarily on the fact that the technologies had not been demonstrated at the scale necessary to establish confidence in their operations. EPA Region 6 has completed a research and literature review and has found that nothing has changed dramatically in the industry since the August 2010 report and there is no

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[7] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>, February 2011.

[8] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011), page 35.

[9] See *Report of the Interagency Task Force on Carbon Capture and Storage* available at http://www.epa.gov/climatechange/policy/ccs_task_force.html.

specific evidence of the feasibility and cost-effectiveness of a full scale carbon capture system for the project and equipment proposed by Copano.

Based on the information reviewed for this BACT analysis, while there are some CO_2 capture technologies that are currently technically infeasible for the affected emission units, EPA has determined that, as a whole, Carbon Capture and Storage (CCS) technology is technologically feasible for this proposed project. Listed below is a summary of those CCS components and technologies that are technically feasible and those CCS components that are not technically feasible for the Copano project.

Step Two Summary for CCS for Copano

CCS Component	CCS Technology	Technical Feasibility
Capture	Post-combustion	Y
	Pre-combustion	N
	Oxyfuel combustion	N
	Industrial separation (natural gas processing, ammonia production)	Y
Transportation	Pipeline	Y
	Shipping	Y
Geological Storage	Enhanced Oil Recovery (EOR)	Y
	Gas or oil fields	N*
	Saline formations	N*
	Enhanced Coal Bed Methane Recovery (ECBM)	N*
Ocean Storage	Direct injection (dissolution type)	N*
	Direct injection (lake type)	N*
Mineral carbonation	Natural silicate minerals	N*
	Waste minerals	N*
Large scale CO_2 Utilization/Application		N*

* Both geologic storage and large scale CO_2 utilization technologies are in the research and development phase and currently commercially unavailable.[10]

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Carbon capture and storage (up to 90%),
- Waste Heat Recovery (18% to 26% reduction in fuel combustion),

[10] U.S. Department of Energy, *Carbon Sequestration Program: Technology Program Plan*, page 20-23.

- Instrumentation and Control System,
- Periodic maintenance and tune-ups,
- Turbine Design.

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 MMBtu/hr. Based on an 80% efficient process heater, this equates to a heat input rage 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 firing rate of the two turbines and a heater that would otherwise be required. Good heater design, an instrumentation and control system, and periodic tune-ups are all considered effective and have a range of efficiency improvements that cannot be directly quantified; therefore, the above ranking of these technologies is approximate only.

Periodic maintenance and tune-ups consist of 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.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

<u>Carbon Capture and Storage</u>

Copano developed an analysis for CCS that provided the basis for eliminating the technology as a viable control option in step 4 of the BACT process based on economic costs, as well as energy and environmental impacts. The recovery and purification of CO_2 from the stack gases would necessitate significant additional processing, including corresponding energy and environmental/air quality penalties, to achieve the necessary CO_2 concentration for effective sequestration. The additional process equipment required to separate, cool, and compress the CO_2, would require a significant additional water and power expenditure. This equipment would include amine units, cryogenic units, dehydration units, and compression facilities. The power and energy for this additional equipment 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 for the compression requirements, however, the overall GHG emissions resulting from additional fuel combustion would either further increase the cost of the CCS system if the emissions were also captured or, if not captured, reduce the net amount of GHG emissions reduction, making CCS even less effective. Thus, CCS can be eliminated as BACT for this project based on energy and environmental impacts.

In addition, the total annual cost of CCS would be $10,900,000 per year. EPA Region 6 reviewed Copano's CCS cost estimate and believes it adequately approximates the cost of a CCS control for this project and demonstrates those costs are prohibitive in relation to the overall cost of the proposed project without CCS, which is estimated at $145,000,000. Based on a 7% interest rate, and 20 year equipment life, this cost equates to an overall annualized cost of about $13,700,000. The annualized cost of CCS would almost double the cost of the project, and thus CCS has been eliminated as BACT for this project as economically prohibitive.

Turbine Design

The rated efficiency of the turbines is 34.4% at 100% load per Solar's specifications. This does not take into account the heat recovered by the waste heat recovery units (WHRUs). Solar Mars turbines were selected over comparable GE and Siemens turbines. At similar load, the GE turbines were slightly less efficient (33.3%) and the Siemens turbines were slightly more efficient (36.2%) than the Solar Mars turbines. The Solar Mars turbines produce 40% less NOx emissions than the other models considered, while the slightly lower efficiency of the Solar Mars turbines results in only about 5% more GHG emissions than the Siemens turbines. This and additional reasons for selecting the Solar Mars turbines include:

- The Solar turbines produce 40% less NOx emissions than the other models considered;
- Copano has two existing Solar Centaur 60 gas turbine packages;
- Copano has two existing Solar Mars 100 gas turbine packages identical to the ones that will be installed in the Cryogenic 3 Process Unit;
- Copano has an existing maintenance/service contract with Solar;
- Copano operations staff is familiar with the Solar gas turbine package.

Instrumentation and Controls

An instrumentation and control package to continuously monitor the turbine ensures the turbine is operating in the most efficient manner.

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 heat capacity that would otherwise be required for the process. This corresponds to up to 21,000 tpy of GHG emissions reductions (estimated GHG emissions from a natural gas fired heater operated 8,760 hr/yr).

<u>Periodic Maintenance and Tune-ups</u>

Periodic maintenance and tune-ups of the turbines include:

- Preventative 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.

Step 5 – Selection of BACT

To date, other facilities with a combustion turbine and a GHG BACT limit are summarized in the table below:

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Lower Colorado River Authority (LCRA), Thomas C. Ferguson Plant Horseshoe Bay, TX	combined cycle combustion turbine and heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine annual net heat rate limited to 7,720 Btu/kWh (HHV) GHG BACT limit of 0.459 tons CO_2/MWhr (net) 365-day average, rolling daily for the combustion turbine unit	2011	PSD-TX-1244-GHG
Palmdale Hybrid Power Plant Project Palmdale, CA	combined cycle combustion turbine and heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine annual net heat rate limited to 7,319 Btu/kWh (HHV) GHG BACT limit of 0.387 tons CO_2/MWhr (net) 365-day average, rolling daily for the combustion turbine unit	2011	SE 09-01
Calpine Russell City Energy Hayward, CA	600 MW combined cycle power plant	Energy Efficiency/ Good Design & Combustion Practices	Combustion Turbine Operational limit of 2,038.6 MMBtu/kWh	2011	15487

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
PacifiCorp Energy Lakeside, UT	combined cycle turbine	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine BACT limit of 950 lb CO_2e/Mwhr	2011	DAQE-IN0130310010-11
Kennecott Utah Copper-Repowering South Jordan, UT	275 MW combined combustion	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine BACT limit of 1,162,552 tpy CO_2e rolling 12-month period	2011	DAQE-IN105720026-11
Calpine Deer Park Energy Center Deer Park, TX	168 MW/180 MW combustion turbine generator with heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	0.460 tons CO_2/MWh on a 30 day rolling average	2012	PSD-TX-979-GHG
Calpine Channel Energy Center Pasadena, TX	168 MW/180 MW combustion turbine generator with heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	0.460 tons CO_2/MWh on a 30 day rolling average	2012	PSD-TX-955-GHG

The turbines for Copano will have a 11.86 MW output each. This is considerably smaller than the turbines listed in the table above and also serve a different function. The Copano turbines are to be used for compression of natural gas and not for power generation to operate Copano's Houston Central Gas Plant.

The following specific BACT practices are proposed for the turbines:

- *Turbine Design* – Turbine will be designed for maximum efficiency. The turbines have a minimum thermal efficiency of 40% with waste heat recovery unit (WHRU), on a 12-month rolling average basis. This is equivalent to 0.84 lb of CO_2e per hp-hr.
- *Waste Heat Recovery* – The heat recovery system will be designed to recover and utilize the waste heat in the turbine exhaust.
- *Periodic Maintenance and Tune-up* – Preventative maintenance, cleaning, and implementation of the manufacturer's recommended inspection and maintenance program will ensure continued operation at maximum thermal efficiency.
- *Instrumentation and Controls* – Instrumentation and controls will be applied to the combustion turbine for effective control of the turbine configuration.

BACT Limits and Compliance:

Copano shall demonstrate compliance with a BACT limit of 40 % efficiency with WHRU which equates to 0.84 lbs of CO_2e/hp-hr, on a 12-month rolling average basis. While Solar has rated the efficiency of the turbines as 34.4% at 100% load, Copano plans on operating the turbines between 50% to 100% load. The turbine only efficiency of 25% at an average turbine load of 70% is appropriate to reflect the expected gas processing rate variations and ambient conditions which affect actual turbine toad. Assuming the WHRU has a linear relationship to the plant throughput, we can calculate the energy recovered giving the combustion turbine and WHRU a thermal efficiency of 42% when the combustion turbine is operating at 70% load. Copano will measure flow and temperature on the hot oil system that uses the recovered heat. The amount of heat (MMBtu/hr) recovered by the WHRU can be calculated from these measurements and converted to hp and then added to the hp output of the turbine alone to obtain a total output of the overall system for use in calculating the efficiency and the CO_2e emissions. Copano shall install a monitoring computer system that will automatically calculate efficiency for each hour of operation using monitored firing rate and turbine output in hp-hr.

Copano shall install and operate a Waste Heat Recovery Unit (WHRU) with a capacity of at least 43 MMBtu/hr on each turbine to recover heat from the turbine exhaust. These systems will eliminate the need for a fired stand alone heater and will provide sufficient heat for the Inlet Gas Heater, Regeneration Gas Heater, Amine Reboiler, and Trim Reboiler.

Copano will maintain records of turbine tune-ups and maintenance. In addition, records of fuel temperature, ambient temperature, and stack exhaust temperature will be maintained for the combustion turbines. Copano shall implement Solar's recommended comprehensive inspection and maintenance program for the turbines.

Copano shall install an instrumentation and control package to include:

- Gas flow rate monitoring,
- Fuel gas flow and usage,
- Exhaust gas temperature monitoring,
- Pressure 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.

Copano will demonstrate compliance with the CO_2 limits for the turbines based on metered fuel consumption and using the average high heat value (HHV) calculated according to the requirements at 40 CFR §98.33(a)(2)(ii), and the default CO_2 emission factor for natural gas from 40 CFR Part 98 Subpart C, Table C-1 and/or fuel composition and mass balance. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(2)(i) is as follows:

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).
HHV = Annual average high heat value of the gaseous fuel (MMBtu/scf). The average HHV shall be calculated according to the requirements at §98.33(a)(2)(ii).
EF = Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/MMBtu).
$1x10^{-3}$ = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The proposed permit also includes an alternative compliance demonstration method, in which Copano may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (i.e., HHV). To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling basis.

An initial stack test demonstration will be required for CO_2 emissions from each emission unit. An initial stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emission are less than 0.01% of the total CO_2e emissions from the heaters and are considered a *de minimis* level in comparison to the CO_2 emissions, making initial stack testing impractical and unnecessary.

IX. Heaters (HTR-3 and HTR-4)

The proposed Cryogenic Process Unit will be equipped with two new natural gas fired heaters (HTR-3 and HTR-4). The heaters will each have a capacity of 25 MMBtu/hr (HHV) and will be operated no more than 600 hours per year. These heaters provide supplemental heat as needed. The heaters will only be utilized during the startup and shutdown of the combustion turbines, or for emergency purposes when a combustion turbine is not operational.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Periodic Tune-up* – Periodically tune-up 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.
- *Carbon Capture and Storage* – Capture and compression, transport and geologic storage of the CO_2.

Step 2 – Elimination of Technically Infeasible Alternatives

Use of low carbon fuels, heater design, and periodic tune-ups are considered feasible. CCS will not be considered further based on the evaluation in section IX above. Waste heat recovery is not applicable to intermittently operated combustion units, and is therefore rejected for the heaters.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Use of low carbon fuels (up to 100% for fuels containing no carbon),
- Heater design (up to 10%), and
- Periodic tune-up
- Heater air/fuel control

Virtually all GHG emissions from fuel combustion result from the conversion of carbon in the fuel to CO_2. Fuels used in industrial processes and power generation are typically 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 emissions factor in lb/MMBtu about 55% of that of subbituminous coal. Process fuel gas is a byproduct of chemical processes that typically contain a higher fraction of longer-chain carbon compounds than natural gas and thus results in more CO_2 emissions. 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 is not produced from the processes at the Houston

Central Gas Plant, and therefore is not a viable fuel. Natural gas is the lowest carbon fuel available for use in the proposed heaters.

Good heater design, periodic tune-ups, and heater air/fuel control 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 and Plant Managers (Environmental Energy Technologies Division, University of California, sponsored by US EPA, June 2008). This report addressed improvements to existing energy systems as well as new equipment; thus, the higher end range of the 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.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Use of Low Carbon 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 choice for most industrial facilities, especially natural gas processing facilities, in addition to being the lowest carbon fuel available.

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:

- Preventative maintenance check of gas flow meters,
- Preventative 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.

Heater Air/Fuel Controls

Manual controls of the air/fuel ratio enable the heaters to operate under optimal conditions ensuring heater efficiency.

Step 5 – Selection of BACT

Copano proposes to use efficient heater design, use of natural gas, and tune-ups performed as needed are proposed as BACT for the heaters. The following specific BACT practices are proposed for the heaters:

- 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 are needed and per vendor recommendations.
- Limit the operational use of the heaters to no more than 600 hours per year per heater on a 12 month rolling basis.

Use of these practices corresponds with a permit limit of 877 tpy CO_2e for each heater. Compliance with this limit will be determined by calculating the emissions on a monthly basis, and keeping a rolling total of hours of operation.

X. Regenerative Thermal Oxidizer (RTO-3)

The acid gas stream from the amine treating unit, consisting primarily of CO_2, contains VOCs, H_2S, and CH_4 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 thermal oxidizer will have a hydrocarbon destruction and removal efficiency (DRE) of at least 99% for methane. The BACT analysis looked at other options to the RTO.

Step 1 – Identification of Potential Control Technologies

- Use of a Well Designed RTO, Instrumentation and Controls to Ensure Efficient Operation of RTO, and Inspection and Maintenance of RTO,
- Use of a Flare, and
- Carbon Capture and Storage

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Carbon Capture and Storage
- Use of an RTO including instrumentation and control package and manufacturer's inspection and maintenance program, and
- Use of a flare.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

<u>Carbon Capture and Storage</u>

The viability of CCS has been discussed previously in Section IX and is not considered a viable option at this time. However, for completeness, Copano provided a cost analysis for CCS applied to the acid gas stream. 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. Based on these excessive costs, CCS was rejected from further consideration as a control option for this stream.

<u>Use of an RTO</u>

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 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.

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, the 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 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 preventative maintenance on RTO instruments and control package once per year.

Using these BACT practices above will result in a BACT limit for the RTO of 69,459 tpy CO_2e. Compliance with this limit will be determined by calculating the emissions based on continuously monitored flow rates and the stream composition of both the flash gas stream and the acid gas stream.

XI. Process Fugitives (CRYO3 FUG)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The additional methane emissions from process fugitives have been conservatively estimated to be 465 tpy as CO_2e. Fugitive emissions of methane are negligible, and account for less than 0.25% of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

The only identified control technology for process fugitive emissions of CO_2e is the 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.

Step 2 – Elimination of Technically Infeasible Alternatives

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

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Although technically feasible, use of an LDAR program to control the negligible amount of GHG emissions that occur as process fugitives is clearly cost prohibitive. However, if an LDAR program is being implemented for VOC control purposes, it will also result in effective control of the small amount of GHG emissions from the same piping components. Copano uses TCEQ's 28M[11] 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.

Step 5 – Selection of BACT

Due to the relatively small amount of GHG emissions from process fugitives, imposition of a numerical limit for these emissions is not feasible. The only available BACT emission reduction strategy is implementation of an LDAR program. Given that Copano will be implementing the TCEQ 28M LDAR program for VOC fugitives under the TCEQ regulations governing the Oil

[11] The boilerplate special conditions for the TCEQ 28M LDAR program can be found at http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28m.pdf.

and Gas Standard Permit. EPA has evaluated Copano using the TCEQ 28M LDAR program for GHG fugitive emissions as well. EPA determined that the monitoring under the TCEQ 28M LDAT program is reasonable for GHG as well, given Copano is already applying the program for VOC emissions. Accordingly, BACT for GHG fugitive emissions will be the implementation of the TCEQ 28M LDAR program.

XII. Threatened and Endangered Species

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7(a)(2), EPA is relying on a Biological Assessment (BA) prepared by the applicant and adopted by EPA. EPA designated Copano and its consultant, Whitenton Group, Inc. ("Whitenton"), as non-federal representatives for purposes of preparation of the BA.

A draft BA identified six (6) federally listed endangered or threatened species for Colorado County, Texas:

Federally Listed Species for Colorado County by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Attwater's greater prairie-chicken	*Tympanuchus cupido attwateri*
Interior least tern	*Sterna antillarum athalassos*
Whooping Crane	*Grus americana*
Mammals	
Louisiana Black Bear	*Ursus americanus luteolus*
Red Wolf	*Canis rufus*
Amphibians	
Houston Toad	*Bufo houstonensis*

Issuance of the proposed permit will have no effect on any of the six listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area. A possible area of potential Houston toad habitat within the action area was further investigated by Whitenton Group and a contracted Houston toad expert, Dr. Michael Forstner. The nearest recorded observation of the Houston toad to the project area is approximately 9.3 miles to the west in Lavaca County. The field assessment identified a narrow band of potential dispersal habitat (loosely connected terrestrial habitats which provide dispersal connectivity for the juveniles during recruitment to the breeding population) at Middle Sandy Creek in the northern portion of the action area. However, Dr. Forstner concluded that, while Middle Sandy Creek could serve as potential dispersal habitat, it is not likely to be utilized and is a path to unsuitable breeding and occupied habitats and there is no record of Houston toads ever traveling more than approximately 10 kilometers (6.2 miles) or more over open terrain, with limited or no suitability, to reach suitable habitat. Therefore, Dr. Forstner concluded that there does not seem to be any reasonable interpretation that would support conclusions of the Houston toad being present at the site today, nor of its use of the site in the near term given habitat conditions.

Because of EPA's "no effect" determination, no further consultation with the USFWS is necessary. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XIII. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties on or eligible for inclusion in the National Register of Historic Places. To make a determination, EPA relied on and adopted a cultural resource report prepared by Horizon Environmental Services ("Horizon") at the request of Whitenton Group, Inc, Copano's consultant, submitted on December 5, 2012.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 8 acres of land within and adjacent to the construction footprint of the existing facility. Horizon performed an archaeological survey within the APE that included a pedestrian survey and shovel testing of the property. Horizon conducted a desktop review on the archaeological background and historical records within a 1-mile radius area of potential effect (APE) which included a review of the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). Based on the information provided in the review, no archaeological resources or historic structures were found within the APE. Additionally, two other previous archaeological surveys in 2010 and 2011 sponsored by the Federal Energy Regulatory Commission (FERC) and Lower Colorado River Authority (LCRA), respectively, were conducted in the general vicinity and both surveys yielded negative results in the vicinity of the APE.

EPA Region 6 determines that because no historic properties are located within the APE and that a potential for the location of archaeological resources is low within the construction footprint itself, issuance of the permit to Copano will not affect properties on or potentially eligible for listing on the National Register.

On December 4, 2012, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XIV. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGs at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XV. Conclusion and Proposed Action

Based on the information supplied by Copano, our review of the analyses contained the TCEQ PSD Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue Copano a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

APPENDIX

Annual Facility Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month, rolling average, shall not exceed the following:

Table 1. Facility Emission Limits

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
TURB-5	TURB-5	Combustion Turbine	CO_2	65,033	65,097	40% efficiency, equates to 0.84 lbs CO_2e/hp-hr. See permit condition III.A.1.m.
			CH_4	1		
			N_2O	0.1		
TURB-6	TURB-6	Combustion Turbine	CO_2	65,033	65,097	40% efficiency, equates to 0.84 lbs CO_2e/hp-hr. See permit condition III.A.1.m.
			CH_4	1		
			N_2O	0.1		
HTR-3	HTR-3	Supplemental Heater	CO_2	876	877	Limit use to 600 hours/year. Use of Good Combustion Practices. See permit condition III.A.2.c. through III.A.2.n.
			CH_4	Negligible[4]		
			N_2O	Negligible[4]		
HTR-4	HTR-4	Supplemental Heater	CO_2	876	877	Limit use to 600 hours/year. Use of Good Combustion Practices. See permit condition III.A.2.c. through III.A.2.n.
			CH_4	Negligible[4]		
			N_2O	Negligible[4]		
RTO-3	RTO-3	Regenerative Thermal Oxidizer	CO_2	69,452	69,459	Use of good combustion practices. See Special Conditions III.A.3.
			CH_4	0.3		
			N_2O	Negligible[4]		
CRYO3 FUG	CRYO3 FUG	Fugitive Process Emissions	CH_4	Not Applicable	Not Applicable	Implementation of LDAR Program. See permit condition III.A.5.
Totals[5]			**CO_2**	**201,270**	**CO_2e 201,871**	
			CH_4	**25**		
			N_2O	**0.2**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling basis.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310
4. All values indicated as negligible are less than 0.01 TPY with appropriate rounding.
5. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. These totals are given for informational purposes only and do not constitute emission limits.