Sound Environmental Solutions, Inc.

August 5, 2014

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Ms. Nevine Salem
US EPA, Region 6
Air Permits Section (6PD-R)
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

Re: GHG PSD Permit Application
Nuevo Midstream, LLC
Ramsey Gas Plant Expansion
Reeves County, Texas

Dear Nevine:

Please find enclosed a revised Final PSD for GHG Pollutants Air Permit Application. It includes the corrections that we discussed between January 2014 and August 2014. Some of the numbers have changed, so the Draft Permit and Appendix A of the SOB will also have to be updated.

If you have any questions, please feel free to contact Rachel Pappworth at (713) 973-6085 or rpappworth@ses-inc.net or Dwight Serrett at his direct office number of (713) 337-6510, his Orla, Texas cell number of (432) 257-2094 or his Houston cell number of (713) 562-6635or at ds@nuevomidstream.com

Sincerely,
Sound Environmental Solutions, Inc.

S S R Pappworth

S.S. Rachel Pappworth, P.E.
Enclosures

cc: Mr. Clint Cone, Nuevo Midstream, Ramsey Gas Plant

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Sound Environmental Solutions, Inc.

NUEVO MIDSTREAM, LLC

RAMSEY GAS PLANT
REEVES COUNTY, TEXAS

U. S. ENVIRONMENAL PROTECTION AGENCY, REGION 6

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) FOR GREENHOUSE GAS EMISSIONS AIR PERMIT APPLICATION

January 2014
Revised August 2014

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SECTION 1.0

1.0 INTRODUCTION

The Ramsey Gas Plant (Ramsey) is a natural gas processing plant located in Reeves County, Texas, north of Orla. The facility is owned and operated by Nuevo Midstream, LLC (Nuevo).

1.1 Currently Permitted Facility

After Nuevo acquired the original plant (Ramsey I Plant), the development of shale gas plays in the area led to an opportunity to treat and process additional gas. In order to accommodate the increase, the Ramsey Gas Plant has been expanded and permitted for the Ramsey I Plant, the 100 MMSCF/D Ramsey II Plant, the 200 MMSCF/D Ramsey III Plant and the associated 475-gallon per minute (gpm) and 1,300-gpm amine units. The original plant and these expansions are authorized by Standard Permit 101511 and General Operating Permit (GOP #514, No. O3546). Nuevo is currently finishing the commissioning of the Ramsey II Plant and the 475-gpm and 1,300-gpm amine units and is in the process of constructing the 200 MMSCF/D Ramsey III Plant.

As is common in the construction of multi-phased projects, there were some changes from the originally facility design, for example because of equipment availability or because of changing market conditions. A streamlined minor modification application was submitted to the TCEQ in November 2013, with additional data having been provided in December 2013.

1.2 Proposed Expansion Covered by this application

The continued development of the shale gas plays in the area has exceeded all predictions and has resulted in the need for additional processing and treating capacity. In preparation to handle this future gas, Nuevo is proposing to build an additional three facilities (Ramsey IV, V and VI Plants). It is currently predicted that the Ramsey IV Plant, a 200 MMSCF/D cryogenic plant and associated 1,000-gpm Amine Plant I, will be needed in late 2015, the Ramsey V Plant, another 200 MMSCF/D cryogenic plant, will be needed in late 2017, and that the Ramsey VI Plant, another 200 MMSCF/D cryogenic plant and associated 1,000-gpm Amine Plant II, will be installed in 2019. The timing of the phases will be dependent on actual market conditions and are provided as a best current estimate only.

The purpose of this application is to apply for a Prevention of Significant Deterioration (PSD) Permit for greenhouse gases (GHGs), to cover the expansion of the currently permitted facility. As the Texas Commission on Environmental Quality (TCEQ) does not currently have the regulations in place to process a PSD permit for greenhouse gases (GHGs), this PSD permit application for GHGs is being submitted to the Environmental Protection Agency (EPA) Region 6. An application for the criteria pollutants has been submitted to TCEQ. An electronic copy of this document is being submitted to EPA with this document.

1.3 Gas Sources

The Ramsey Gas Plant currently receives inlet gas from three main sources. The first, Avalon Shale gas, comes from the area north of the plant. It typically contains higher concentrations of CO_2 as well as traces of H_2S and enters the Plant through the Avalon Inlet. The second gas stream comes from the Wolfcamp formation around the plant and enters the Plant through the

Wolfcamp Inlet. It typically contains no H_2S, but does have low levels of CO_2. The third source of gas is the Bone Spring gas which enters through the Plant already combined with the Avalon and/or Wolfcamp streams. This gas contains some CO_2 but no H_2S. It is obviously not known at this stage what the exact make-up of the inlet gas will be for the proposed expansion. However, conservatively, the percent of Avalon gas entering the plant is anticipated to be about 33%. In order to be even more conservative and develop a "worst case scenario", it has been assumed that the amount of Avalon gas in the inlet would be 40%, with the Wolfcamp and Bone Spring each making up 30%.

A summary of the typical analyses for the Ramsey Gas Plant raw inlet gas streams is presented in Table 1.

Copies of laboratory results are presented in the Technical Specification Section (Section 6).

TABLE 1
TYPICAL INLET GAS ANALYSES

Component	Avalon Inlet	Wolfcamp Inlet	Bone Spring Inlet	Typical Inlet Composite Gas
	Mole Percent			
Methane	71.9545	78.872	76.814	75.488
Ethane	9.499	10.672	11.674	10.503
Propane	5.133	4.474	5.907	5.168
Iso Butane	0.653	0.865	0.758	0.748
Nor Butane	1.564	1.598	1.861	1.663
Iso Pentane	0.409	0.510	0.399	0.436
Nor Pentane	0.436	0.559	0.498	0.492
Hexane+	0.620	1.584	0.660	0.921
Nitrogen	1.562	0.592	1.102	1.133
Carbon Dioxide	8.169	0.274	0.327	3.448
H_2S	0.0005	0.000	0.000	0.0002
Total %	**100.00**	**100.00**	**100.00**	**100.00**

1.4 Facility Description

The Ramsey Gas Plant is located in Reeves County (see Figure 1– Site Location Map, Section 5). Reeves County is rural with no large town or any industry in the immediate area. Most of the county, including the area around the Ramsey Gas Plant, is a broad gently-sloping plain, with sparse grasses, scrub brush, cacti and mesquite. The currently permitted facility occupies about 21.5 acres. After the proposed modification is completed it will occupy approximately 50 acres.

1.4.1 Currently Permitted Facility

The currently permitted Ramsey I through Ramsey III Plants consist of inlet separators, low pressure inlet gas compression, ten (10) residue gas compressors, one (1) 100-MMSCF/D and one (1) 200 MMSCF/D cryogenic processing plant, molecular sieve dehydration and associated heaters, 475-gpm and 1,300-gpm amine treaters with associated heaters, a Regenerative Thermal Oxidizer (RTO), an emergency flare, pressurized product storage, truck loading, seven (7) condensate and produced water storage tanks and two (2) natural gas-fired generator packages to provide electricity on an interim basis while the power company establishes the full required power supply, after which they will be removed or be converted to emergency back-up generators.

1.4.2 Proposed Expansion of the Ramsey Facility

It is anticipated that the new development will be constructed in phases as market conditions allow, in a similar manner to the previous expansions. It is proposed that the expansions will consist of:

- Ramsey IV Plant
- 1,000-gpm Amine Plant I
- Ramsey V Plant
- Ramsey VI Plant
- 1,000-gpm Amine Plant II.

The equipment associated with the currently permitted facility and these expansions is summarized in Table 2 and are also shown on the Site Plot Plan (see Figure 2 in Section 5).

TABLE 2
EMISSION UNITS ASSOCIATED EXPANSION OF RAMSEY GAS PLANT

RAMSEY I PLANT	RAMSEY II PLANT	RAMSEY III PLANT	RAMSEY IV PLANT	RAMSEY V PLANT	RAMSEY VI PLANT
Currently Permitted			**This Application**		
ENGINES					
Caterpillar G3408C LE (COMP-1B)	Caterpillar G3516B LE (COMP-5)	Caterpillar G3612 LE (COMP-10) or equivalent	Caterpillar G3612 LE (COMP-15) or equivalent	Caterpillar G3612 LE (COMP-20) or equivalent	Caterpillar G3612 LE (COMP-25) or equivalent
Caterpillar G-3412 TA (COMP-2)	Caterpillar G3516B LE (COMP-6)	Caterpillar G3612 LE (COMP-11) or equivalent	Caterpillar G3612 LE (COMP-16) or equivalent	Caterpillar G3612 LE (COMP-21) or equivalent	Caterpillar G3612 LE (COMP-26) or equivalent
	Caterpillar G3516B LE (COMP-7)	Caterpillar G3612 LE (COMP-12) or equivalent	Caterpillar G3612 LE (COMP-17) or equivalent	Caterpillar G3612 LE (COMP-22) or equivalent	Caterpillar G3612 LE (COMP-27) or equivalent
	Caterpillar G3516B LE (COMP-8)	Caterpillar G3612 LE (COMP-13) or equivalent	Caterpillar G3612 LE (COMP-18) or equivalent	Caterpillar G3612 LE (COMP-23) or equivalent	Caterpillar G3612 LE (COMP-28) or equivalent
	Caterpillar G3516B LE (COMP-9)	Caterpillar G3612 LE (COMP-14) or equivalent	Caterpillar G3612 LE (COMP-19) or equivalent	Caterpillar G3612 LE (COMP-24) or equivalent	Caterpillar G3612 LE (COMP-29) or equivalent
	Caterpillar G3520C-HV (G-1)				
	Caterpillar G3516 TALE (G-2)				
Blowdowns (BD)		Blowdowns (BD2)	Blowdowns (BD3)	Blowdowns (BD4)	Blowdowns (BD5)

RAMSEY I PLANT	RAMSEY II PLANT	RAMSEY III PLANT	RAMSEY IV PLANT	RAMSEY V PLANT	RAMSEY VI PLANT
Currently Permitted			**This Application**		
HEATERS and STILL VENTS					
	11.44 MMBtu/hr Regen Gas Heater (H-3)	36 MMBtu/hr or equivalent Hot Oil Heater (H-6)	36 MMBtu/hr or equivalent Regen Gas Heater (H-8)	36 MMBtu/hr or equivalent Regen Gas Heater (H-10)	36 MMBtu/hr or equivalent Regen Gas Heater (H-12)
1 MMBtu/hr Hot Oil Heater (H-2)	33.4 MMBtu/hr Hot Oil Heater (H-4)	40.4 MMBtu/hr Hot Oil Heater (H-7A)	60 MMBtu/hr or equivalent Hot Oil Heater (H-9)		60 MMBtu/hr or equivalent Hot Oil Heater (H-11)
		40.4 MMBtu/hr Hot Oil Heater (H-7B)			
	24 MMBtu/hr Hot Oil Heater (H-5)				
	Amine Still Vent (A-2)	Amine Still Vent (A-3)	Amine Still Vent (A-4)		Amine Still Vent (A-5)
	Emergency Flare (F-2R)	Regenerative Thermal Oxidizer (RTO-3)	Regenerative Thermal Oxidizer (RTO-4)		Regenerative Thermal Oxidizer (RTO-5)
TANKS					
210 bbl Condensate Tank (T-1)	210 bbl Condensate Tank (T-2)	210 bbl Condensate Tank (T-4)			
	210 bbl Condensate Tank (T-3)	210 bbl Condensate Tank (T-5)			
	210 bbl Produced Water Tank (T-8)	210 bbl Produced Water Tank (T-9)			
MISC					
Truck Loading		Truck Loading			
FUG1		FUG2	FUG4	FUG5	FUG6

The shaded area of the Table denotes the currently permitted facilities

2.0 PROCESS DESCRIPTION

2.1 Currently Permitted

Currently, inlet gas from the low-pressure inlet separator is compressed by the Caterpillar G3408C LE IC engine driven screw compressor (COMP-1B) and boosted to plant inlet pressure by the Caterpillar 3412 TA IC engine driven booster compressor (COMP-2). This gas is combined with the high pressure Avalon, Bone Spring and Wolfcamp inlets and routed to one or both of the amine units (475-gpm or 1,300-gpm).

In the existing amine units, lean amine solution is fed to the amine contactor and absorbs the H_2S and CO_2 (acid gas) in the inlet gas. The rich amine solution from the amine contactor is flashed in the amine flash drum and routed to the appropriate amine still where the acid gas is stripped from the amine solution with steam generated by heat exchanged with hot oil in the amine reboilers. The hot oil used to regenerate the amine is heated by hot oil heaters (H-4 and/or H-7A and H-7B). The gas flashed in the amine flash drum is recycled to the suction of the low pressure inlet compressors and is not an emissions source. The acid gas from the amine still vents (A-2 and A-3) is normally routed to the Regenerative Thermal Oxidizer (RTO-3) with the back-up option of routing the still vents to the emergency flare (F-2R) in the event the RTO is down during routine maintenance or an upset situation.

The sweet gas from the amine units is routed to the molecular sieve dehydrators of Ramsey II Plant and/or Ramsey III Plant. The molecular sieve dehydrators are regenerated by Mole Sieve Regen Heaters (H-3 and/or H-6). From the molecular sieve dehydrators the gas is routed to the respective cryogenic plants.

The clean dry gas goes through multiple heat exchangers where the temperature is dropped and the ethane and heavier components of the gas stream are liquefied. The remaining gas and liquids mixture is sent to the demethanizer where the methane gas is stripped from the ethane rich liquid by warm vapors as it flows across the trays and through the packed sections of the demethanizer tower. The heat required for this distillation is supplied by exchange with the warm inlet gas. If deethanization is required, additional heat is supplied by hot oil heaters (H-5) for Ramsey II Plant or (H-6) for Ramsey III Plant.

Propane refrigeration is required for inlet gas chilling and the single column overhead recycle process is contained in a closed-loop process. Liquid propane is evaporated, drawing the latent heat of vaporization from the process. The low pressure vapor is compressed using four (4) 1,250-hp electric driven screw compressors for Ramsey II Plant and three (3) 1,750-hp electric driven screw compressors for the Ramsey III Plant. The vapor is condensed in an aerial cooler and flows into the propane accumulator. Liquid propane is level controlled into the economizer where the non-condensable gases flash, cooling the propane to 55 ^{o}F. The vapor from the economizer is returned to the refrigerant compressor inter-stage, reducing the compression horsepower required. The liquid propane in the economizer is routed to the chillers in the cryogenic plant, vaporized and returned to the electric driven screw compressors where the process is repeated inside the closed-loop.

The Y-grade liquid product normally flows from the cryogenic section to the product surge tank prior to being shipped off-site by pipeline. If necessary, the facility also has the ability to "deethanize" the liquid product in the demethanizer and store it in pressurized tanks prior to being shipped offsite by truck. The pressurized product loading operation is a closed system with no emissions.

Condensate collected from the low pressure inlet separator is routed to the existing Condensate Tanks (T-1 through T-4) prior to being loaded into trucks. High pressure liquids from the high pressure inlet separators, and compressor dumps are flashed to the flash tank. The condensate from the flash tank is stabilized using hot oil from hot oil heater (H-2) and is also routed to the existing storage tanks (T-1 through T-4). The facility is permitted for up to seven (7) condensate or produced water storage tanks. In the event that the condensate and produced water volumes warrant the need for additional storage capacity, the three (3) remaining permitted tanks will be installed. The vapors from the flash tank become part of the suction of the low-pressure compressor (COMP-1B).

The compressor blow downs (BD), which includes routine maintenance, start-up and shutdown of the facility, and temporary maintenance VOC emissions are authorized by the new PBR 106.359, until they were rolled into the Title V permit.

There are two (2) generators (G-1 and G-2) that were installed to temporarily provide power while a substation is built, and will be converted to emergency back-up use or removed once the substation is completed.

The existing, permitted equipment also includes one (1) 100 MMSCF/D cryogenic plant (currently operational) and one (1) 200 MMSCF/D cryogenic plant (currently under construction). Hot oil heaters H-5 and H-6 supply process heat used in the demethanizer for each of these plants.

The residue gas from the demethanizer is compressed for sale by five (5) Caterpillar G3516B LE (or equivalent) gas engine driven compressors (COMP-5, COMP-6, COMP-7, COMP-8 and COMP-9) for Ramsey II Plant and five (5) Caterpillar G3612 LE (or equivalent) gas engine driven compressors (COMP-10, COMP-11, COMP-12, COMP-13 and COMP-14) for Ramsey III Plant.

Pipeline quality residue gas is used for fuel gas under normal circumstances.

2.2 Proposed Facility Expansion

The facility expansion will include the addition of two (2) 1,000-gpm amine units (Amine Plants I and II). The process description is identical to the 475-gpm and 1,300-gpm amine units above. The amine will be regenerated by heat from hot oil heaters H-9 and H-11 respectively. Amine Plants I and II will be associated with Amine still vent A-4 and RTO-4 and amine still vent A-5 and RTO-5 respectively.

The facility expansion will also include the addition of three (3) 200 MMSCF/D cryogenic processing plants. The plants will be Ramsey IV Plant, Ramsey V Plant and Ramsey VI Plant. The process description for these plants is as described above for Ramsey II Plant and Ramsey III Plant. The molecular sieve regeneration and process heat for these plants will be furnished by regen heaters H-8, H-10 and H-12 respectively. The residue gas from each plant will be compressed by five (5) Caterpillar G3612 LE (or equivalent) gas engine driven compressors. Ramsey IV Plant will have COMP-15, COMP-16, COMP-17, COMP-18 and COMP-19. Ramsey V Plant will have COMP-20, COMP-21, COMP-22, COMP-23 and COMP-24. Ramsey VI Plant will have COMP-25, COMP-26, COMP-27, COMP-28 and COMP-29.

Pipeline-quality facility residual gas will continue to be used for fuel gas under normal circumstances.

A process flow diagram is provided as Figure 3 in Section 5.

3.0 PSD APPLICABILITY FOR GHG

Under the Clean Air Act (CAA), new major stationary sources of certain air pollutants, defined as "regulated NSR pollutants," and major modifications to existing major sources are required to, among other things, obtain a PSD permit prior to construction or major modification. Once major sources become subject to PSD, these sources must, in order to obtain a PSD permit, meet the various PSD requirements. For example, they must apply BACT, demonstrate compliance with air quality related values and PSD increments, address impacts on special Class I areas (e.g., some national parks and wilderness areas), and assess impacts on soils, vegetation, and visibility. How the proposed project meets these PSD requirements for GHGs is the subject of this section of this document.

The CAA applies the PSD requirements to any "major emitting facility" that is constructed (if the facility is new) or undertakes a modification (if the facility is an existing source). The term "major emitting facility" is defined as a stationary source that emits, or has a potential to emit (PTE) of, at least 100 TPY, if the source is in one of 28 listed source categories, or, if the source is not, then at least 250 TPY, of "any air pollutant." For existing facilities, the CAA adds a definition of modification, which, in general, is any physical or operational change that "increases the amount" of any air pollutant emitted by the source.

EPA's regulations implement these PSD applicability requirements through use of different terminology, and, in the case of GHGs, with additional limitations. Specifically, the regulations apply the PSD requirements to any major stationary source that begins actual construction (if the source is new) or that undertakes a major modification (if the source is existing). The term major stationary source is defined as a stationary source that emits, or has a PTE of, at least 100 TPY if the source is in one of 28 listed source categories, or, if the source is not, then at least 250 TPY, of regulated NSR pollutants, "Criteria Pollutants". The proposed project is not included in one of the 28 listed source categories and is therefore subject to the 250 TPY major source threshold.

A major modification is defined as "any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant; and a significant net emissions increase of that pollutant from the major stationary source."

EPA rules specify what amount of emissions increase is "significant" for listed regulated NSR pollutants (e.g., 40 TPY for sulfur dioxide, 100 TPY for carbon monoxide), but for any regulated NSR pollutant that is not listed in the regulations, any increase is significant. A pollutant is a "regulated NSR pollutant" if it meets at least one of four requirements, which are, in general, any pollutant for which EPA has promulgated a NAAQS or a new source performance standard (NSPS), certain ozone depleting substances, and "[a]ny pollutant that otherwise is subject to regulation under the Act." PSD applies on a regulated-NSR-pollutant-by-regulated-NSR-pollutant basis. The PSD requirements do not apply to regulated NSR pollutants for which the area is designated as nonattainment. Further, some modifications are exempt from PSD review (e.g., routine maintenance, repair and replacement). A explained above, Nuevo has already submitted a criteria pollutant PSD application for the Ramsey Expansion to the TCEQ and is sending an electronic copy of that application to EPA, with this GHG PSD application.

Beginning on January 2, 2011, GHGs also became a regulated NSR pollutant under the PSD major source permitting program when they are emitted by new sources or modifications in amounts that meet specified applicability thresholds. For PSD purposes, GHGs are a single air pollutant defined as the aggregate group of the following six gases:

- carbon dioxide (CO_2)
- nitrous oxide (N_2O)
- methane (CH_4)
- hydrofluorocarbons (HFCs)
- perfluorocarbons (PFCs)
- sulfur hexafluoride (SF_6)

Emissions of GHGs, in at least specified threshold amounts, are also treated as subject to regulation and therefore as a regulated NSR pollutant. The process for determining whether a source is emitting GHGs in an amount that would make the GHGs a regulated NSR pollutant includes a calculation of, and applicability threshold for, the source based on CO_2 equivalent (CO_2e) emissions, as well as its GHG mass emissions. Consequently, when determining the applicability of PSD to GHGs, there is a two-part applicability process that evaluates both:

- the sum of the CO_2e emissions in TPY of the six GHGs, in order to determine whether the source's emissions are a regulated NSR pollutant; and, if so
- the sum of the mass emissions in TPY of the six GHGs, in order to determine if there is a major source or major modification of such emissions.

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential (GWP). GWP values have been published in Table A-1 of the Greenhouse Gas Reporting Program (GHGRP) (40 CFR Part 98, Subpart A, Table A-1). For any source, since GHG emissions may be a mixture of up to six compounds, the amount of GHG emissions calculated for the PSD applicability analysis is a sum of the compounds emitted at the emissions unit.

The Ramsey Plant is currently a major source for CO, and the proposed project is considered to be a modification. PSD applies to the GHG emissions from a modification if any of the following is true:

Both of the following are true:

- Not considering its emissions of GHGs, the modification would be considered a major modification anyway and therefore would be required to obtain a PSD permit (called an "anyway modification"), and
- The emissions increase and the net emissions increase of GHGs from the modification would be equal to or greater than 75,000 TPY on a CO_2e basis and greater than zero TPY on a mass basis.

Or both:

- The existing source's PTE for GHGs is equal to or greater than 100,000 TPY on a CO_2e basis and is equal to or greater than 100/250 TPY (depending on the source category) on a mass basis, and

- 75,000 TPY on a CO_2e basis and greater than zero TPY on a mass basis.

Or both:
- The existing source is minor for PSD (including GHGs) before the modification, and
- The actual or potential emissions of GHGs from the modification alone would be equal to or greater than 100,000 TPY on a CO_2e basis and equal to or greater than the applicable major source threshold of 100/250 TPY on a mass basis. Note that minor PSD sources cannot "net" out of PSD review.

Assessing PSD applicability for a modification at an existing major stationary source against the GHG emissions thresholds is a two-step process. Step 1 of the applicability analysis considers only the emissions increases from the proposed modification itself and is presented above. Step 2 of the applicability analysis, which is often referred to as "contemporaneous netting," considers all creditable emissions increases and decreases (including decreases resulting from the proposed modification) occurring at the source during the "contemporaneous period." The federal "contemporaneous period" for GHG emissions is no different than the federal contemporaneous period for other regulated NSR pollutants, which covers the period beginning 5 years before construction of the proposed modification through the date that the increase from the modification occurs.

Because PSD applicability for modifications at existing sources requires a two-step analysis, and because, for GHGs, each step requires a mass-based calculation and a CO_2e-based calculation, a total of four applicability conditions must be met in order for modifications involving GHG emissions at existing major sources to be subject to PSD. These four conditions are summarized below.

1) The CO_2e emissions increase resulting from the modification, calculated as the sum of the six GHGs on a CO_2e basis (i.e., with GWPs applied) is equal to or greater than 75,000 TPY CO_2e. No emissions decreases are considered in this calculation (i.e.., if the sum of the change in the six GHGs on a CO_2e basis from an emissions unit included in the modification results in a negative number, that negative sum is not included in this calculation to offset increases at other emissions units).

2) The "net emissions increase" of CO_2e over the contemporaneous period is equal to or greater than 75,000 TPY.

3) The GHG emissions increase resulting from the modification, calculated as the sum of the six GHGs on a mass basis (i.e., with no GWPs applied) is greater than zero TPY. No emissions decreases are considered in this calculation (i.e., if the sum of the change in the six GHGs on a mass basis from an emissions unit included in the modification results in a negative number, that negative sum is not included in this calculation to offset increases at other emissions units).

4) The "net emissions increase" of GHGs (on a mass basis) over the contemporaneous period is greater than zero TPY.

Based on emission estimates, the proposed project is a major modification under PSD not considering its GHG emissions, and the net increase in GHG emissions is estimated to be equal to or greater than 75,000 TPY on a CO_2e basis and greater than zero TPY on a mass basis. Therefore the project is subject to PSD for GHGs.

4.0 TOP DOWN GHG BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

Under the CAA and applicable regulations, a PSD permit must contain emissions limitations based on application of Best Available Control Technology (BACT) for each regulated NSR pollutant. A determination of BACT for GHGs should be conducted in the same manner as it is done for any other PSD regulated pollutant. The scope of the GHG BACT Analysis is the proposed facility modification described in Sections 1.2 and 1.4.2.

EPA recommends that permitting authorities continue to use the Agency's five-step "topdown" BACT process to determine BACT for GHGs. In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top-ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as GHG BACT.

EPA has broken down this analytical process into the following five steps:

- Step 1: Identify all available control options.
- Step 2: Eliminate technically infeasible control options.
- Step 3: Rank remaining control technologies.
- Step 4: Eliminate control options based on collateral impacts.
- Step 5: Select BACT.

The CAA specifies that BACT cannot be less stringent than any applicable standard of performance under the New Source Performance Standards (NSPS). EPA has not promulgated any NSPS that contain emissions limits for GHGs. However, EPA has promulgated several standards that specify emission control practices which are effective for GHGs. These include:

- NSPS for Stationary Spark Ignition Internal Combustion Engines which specifies good combustion practices for natural gas fired engines.
- NSPS for Crude Oil and Natural Gas Production, Transmission and Distribution facilities (40 CFR 60 Subpart OOOO) which specifies practices for limiting fugitive emissions that also limit fugitive GHG emissions.

An initial consideration that is not directly covered in the five steps of the top-down BACT process is the scope of the entity or equipment to which a top-down BACT analysis is applied. EPA has generally recommended that permit applicants conduct a separate BACT analysis for each emissions unit at a facility and has also encouraged applicants and permitting authorities to consider logical groupings of emissions units as appropriate on a case-by-case basis. For purposes of this analysis, proposed emission units of the Ramsey Gas Plant expansion will be grouped for analysis as shown in Table 3 below:

TABLE 3
EMISSION UNITS AND POLLUTANTS THAT REQUIRE GHG BACT ANALYSIS

Unit Group	EPN(s)	Pollutants
Gas Fired Internal Combustion Compressor Engines	C-15 through C-29	• carbon dioxide (CO_2) • nitrous oxide (N_2O) • methane (CH_4)
Hot Oil Heaters, Regeneration Heaters	H-8, H-9, H-10, H-11, H-12	
Amine Still Vents	A-4 and A-5	
RTOs	RTO-4 and RTO-5	
Fugitives	FUG4, FUG5 and FUG6	

No significant amounts hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), or sulfur hexafluoride (SF_6) are in use at the facility and emissions of these compounds are not considered as part of the analysis.
No other equipment or GHG sources are included in the proposed modification.

4.1 Step 1 Identify Available Control Technologies

Step 1 - Step 1 of the top-down approach requires that all available control options that are potentially applicable to the proposed source are identified. Available control options were identified by consulting the EPA's RACT/BACT/LAER clearinghouse, along with other reliable sources. Viable control options are those technologies that have a practical potential for application to the emissions unit and the regulated pollutant under evaluation. The full range of emissions minimization techniques was considered including:

• "End-of-stack" controls,
• Fuel and materials choices,
• Production process design and work practices, and
• Energy usage and conservation techniques

In Step 1 of a criteria pollutant BACT analysis, the following resources are typically consulted to identify potential technologies:

- The EPA Reasonably Available Control technology (RACT)/ Best Available Control technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database;
- Determinations of BACT by regulatory agencies for similar sources, and air permits and permit files from federal or state agencies;

- Engineering experience with similar projects or emission sources;
- Information provided by air pollution control equipment vendors who have produced or implemented controls at a significant number of sources;
- Literature from technical or trade organizations.

One set of draft determinations related to GHG BACT, at a facility similar to the Ramsey Plant but located in Louisiana, was found in the RBLC database. These draft determinations were taken into consideration in determining BACT for the Ramsey Plant.

This analysis also relies on publicly available air permits and permit applications covering similar facilities to establish BACT.

EPA GHG BACT guidance recommends that carbon capture and sequestration (CCS) be evaluated as an available control for projects such as steel mills, refineries, and cement plants where CO_2e emissions levels are in the order of 1,000,000 tpy CO_2e, or for industrial facilities that produce or use high-purity CO_2 streams. However, EPA explained that "[t]his does not mean CCS should be selected as BACT for such sources." The amine still vents are the only CO_2-containing stream produced at the facility, and CCS will be assessed as a potential control technology for that source group. Since the facility processes sulfur-containing field gas, this stream is expected to contain significant amounts of hydrogen sulfide and so require additional processing before entering a CO_2 pipeline for transportation. The proposed Ramsey Plant modification GHG emissions total approximately 595,000 tpy CO_2e (including emissions from Maintenance Startup and Shutdown (MSS) activities). In accordance with EPA guidance, and based on the anticipated relatively low level of CO_2e emissions, CSS will not be considered as an available control option for other sources at the Ramsey Plant.

This BACT analysis focuses on the main sources of CO_2e emission at the Plant. GHG emissions from small sources such as malfunction, start-up and shut down events are included in facility emission estimates, but separate controls for these emissions are not considered in the BACT analysis.

Available control technologies for each unit group include the following:

4.1.1 Gas Fired Internal Combustion Compressor Engines

Natural Gas as Fuel – Selecting inherently lower emitting processes is one recommended form of BACT. For GHG BACT analyses, low carbon density fuel selection is the primary control option that could be considered a lower emitting process. Nuevo proposes to use very low carbon intensity plant residue gas, equivalent to pipeline quality natural gas, as fuel in all on-site combustion equipment. According to 40 CFR 98 Table C-1, only biogas and coke oven gas have lower carbon emissions per unit heat input than natural gas.

Good Combustion, Operations, and Maintenance Practices – Maximizing combustion efficiency can minimize the amount of fuel needed to maintain facility production and so minimize GHG emissions. Good combustion, operations, and maintenance practices for natural gas spark ignition engines are specified in the applicable requirements of NSPS 40 CFR 60 Subpart JJJJ.

Air/Fuel Ratio Controllers – Air/fuel ratio controllers minimize methane emissions from reciprocating engines. Combustion units operated with too much excess air may lead to inefficient combustion, and additional energy will be needed to heat the excess air. Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture and reduce the amount of energy required to heat the stream and, therefore, reduce the carbon emissions. The engine management systems provided by the manufacturer with the engines proposed for the Ramsey Plant expansion integrate speed control, air/fuel ratio control, and ignition/detonation controls so as to maximize combustion efficiency and minimize GHG emissions.

Efficient Engine Design – Large natural gas fired engines utilize either rich burn or lean burn technology to attain required low criteria pollutant emission levels. Rich burn technology controls combustion temperature by maintaining excess fuel in the combustion zone, and is an inherently inefficient combustion process. Lean burn technology, on the other hand, utilizes excess air in the combustion zone. The excess air absorbs heat during combustion reducing the combustion temperature and pressure and greatly reducing levels of criteria pollutants. Lean burn technology provides longer component life and excellent fuel efficiency. The engines selected for the Ramsey Plant expansion incorporate energy efficient, low carbon emission lean burn technology.

Electric Powered Compression – It is technically possible to install large electric motors to power compressors. Electric motors do not produce any significant GHG emissions at the site where they are installed, but the electricity they use is generally associated with GHG emissions from associated power generation facilities. Large compressors like those necessary at the Ramsey Plant require a high-voltage, high amperage electric supply that is not available at the Plant site. Also, net regional GHG emissions from electric powered compression may be higher than that of natural gas powered compressor engines if coal or another high carbon density fuel is used to generate the electric power.

4.1.2 Hot Oil Heaters, Regeneration Heaters

Natural Gas as Fuel – Nuevo proposes to use very low carbon density plant residue gas, equivalent to pipeline quality natural gas, as fuel in all on-site combustion equipment.

Good Combustion, Operations, and Maintenance Practices – Maximizing combustion efficiency can minimize the amount of fuel needed to maintain facility production and so minimize GHG emissions. Good combustion, operations, and maintenance practices for natural gas heaters are described in Table 9.

Combustion Air Controls – Combustion units operated with too much excess air may lead to inefficient combustion, and additional energy will be needed to heat the excess air. Both of these factors tend to increase GHG emissions. Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture.

Fuel Gas Pre-heater / Air Pre-heater – Preheating the fuel gas and air reduces heating load and increases thermal efficiency of the combustion unit. An air pre-heater recovers heat in the heater exhaust gas to preheat combustion air. Preheating the combustion air in this way reduces heater heating load, increases its thermal efficiency, and reduces GHG emissions. Pre-heaters typically increase NOx emissions and so are contraindicated for heaters that are required to meet BACT for NOx. Also, air preheaters require operation of induced draft fans and so increase overall energy consumption. According to the EPA document Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry, (EPA, Office of Air and Radiation, October 2010) preheating is not feasible for heaters with a heat input of less than 50 MMBtu/hour.

Efficient Heater Design – Efficient design improves mixing of fuel and creates more efficient heat transfer. Since Nuevo is proposing to install new equipment, the proposed heaters will be designed to optimize combustion efficiency.

4.1.1 Amine Still Vents

Natural Gas as Fuel – Nuevo proposes to use very low carbon density plant residue gas, equivalent to pipeline quality natural gas, as fuel in all on-site combustion equipment.

Good Combustion, Operations, and Maintenance Practices – The amine unit will be new or updated equipment installed on site. New or updated equipment has better energy efficiency, and therefore minimizes GHGs emitted during combustion. The amine unit will be designed to operate at a minimum circulation rate with consistent amine concentrations. By minimizing the circulation rate, the equipment avoids pulling out additional VOCs and GHGs in the amine streams, which would increase VOC and GHG emissions into the atmosphere. Other good combustion, operations, and maintenance practices for amine still vents are described in Table 9.

Carbon Capture and Sequestration – Capture and transfer of CO_2 from the amine still vents is technically feasible. Since capture and transfer of CO_2 off-site is technically feasible for the proposed project, this option will be evaluated for energy, environmental, and economic impacts. The evaluation and proposed partial implementation of this option is discussed in Section 4.4.1.

Flare – The use of a flare can reduce the CH_4 emissions contained in the stripped amine acid gases. Flares or other VOC controls are required on amine still vents that must meet criteria pollutant BACT. The flare is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Controlling the amine still vent streams with a flare would require significant supplemental fuel to maintain a pilot flame and to increase the heating value of the waste gases to the point that it can be effectively combusted in a flare and so increase CO_2 and CH_4 emissions. Also flares combust at high temperature and so contribute additional N_2O emissions. Flares have a destruction efficiency rate (DRE) of 98% for VOCs and 99% for compounds containing no more than 3 carbons and that contain no elements other than carbon and hydrogen, including CH_4. The combustion of the supplemental fuel and pilot fuel result in an overall increase in the net CO_2e emissions from this source.

Regenerative Thermal Oxidizer (RTO) – Another option to reduce the CH_4 and VOC emitted from the Ramsey Plant is to send stripped amine acid gases to an RTO. The RTO is also an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions, the control of CH_4 and VOC in the process gas at the RTO results in the creation of additional CO_2 emissions. An RTO recovers heat from the exhaust stream, reducing the overall heat input of the plant. RTOs typically have destruction and removal efficiencies greater than of 99% for all VOC and HAP compounds, which is more efficient than a typical flare. In contrast with a flare, which requires the use of supplemental fuel to increase the waste gas heating value as well as a constant pilot, a RTO only uses a minimal amount of natural gas at start up until optimum temperature for combustion is reached and does not require a continuous pilot. This results in lower use of supplemental fuel and lower GHG emissions than expected from an equivalent flare.

Flash Tank Gas Recovery – The amine units will be equipped with flash tanks. The flash tanks will be used to recycle off-gases formed as the pressure of the rich amine streams drops to remove lighter compounds in the stream. These off-gases are recycled back into the plant for reprocessing, instead of venting to the atmosphere or combustion device. The use of flash tanks increases the effectiveness of other downstream control devices.

Condenser – Condensers are supplemental emissions control that reduces the temperature of the still column vent vapors on amine units to condense water and VOCs, including CH_4. The condensed liquids are then collected for further treatment or disposal. The reduction efficiency of the condensers is variable and depends on the type of condenser and the composition of the waste gas, ranging from 50-98% of CH_4 emissions.

4.1.2 RTOs

Natural Gas as Fuel – Nuevo proposes to use very low carbon density plant residue gas, equivalent to pipeline quality natural gas, as fuel in all on-site combustion equipment.

Good Combustion, Operations, and Maintenance Practices – Good combustion and operating practices are a potential control option by improving the fuel efficiency of the RTO. Good combustion, operations, and maintenance practices for RTOs are described in Table 9.

Proper Design – Good RTO design can be employed to destroy any HAPs, VOCs and CH_4 entrained in the waste gas. Nuevo proposes to install new RTOs designed by a well-qualified and experienced manufacturer.

4.1.3 Fugitives

Install sealed or leakless components – Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used. These technologies are generally considered cost prohibitive except for specialized service. Some leakless technologies, such as bellows valves, cannot be repaired without a unit shutdown if they fail. Additional emissions generated during the shutdown and restart offset some or all of the emission reductions sought by installing these components.

Implement NSPS OOOO Leak Detection and Repair (LDAR) programs as required – Method 21 monitoring is effective for identifying leaking CH_4, and although it cannot detect CO_2, it can detect mixed streams that contain CO_2 such as inlet gas or plant residual gas. Method 21 monitoring of the fuel and feed systems for CH_4 is an effective method for control of GHG emissions. NSPS OOOO requires a regular LDAR program that is believed to reduce fugitive VOC emissions by 75-93%, and this program should control fugitive GHG emissions by a similar percent. Nuevo proposes to comply with applicable requirements of NSPS OOOO.

Implement an alternate monitoring program using remote sensing – Alternate monitoring programs, such as remote sensing technologies, have been proven effective in leak detection and repair programs under some circumstances and are also used to detect large releases of hazardous or highly flammable gases. According to the EPA publication Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution (EPA-435/R-11-002, July 2011), remote sensing has a cost effectiveness of $1,795 per ton of methane reduced from natural gas plants. This cost makes remote sensing economically infeasible.

Implement an audio/visual/olfactory (AVO) monitoring program for odorous compounds – Leaking fugitive components can be identified through AVO methods. The fuel gases and process fluids in the piping components are expected to have discernible odor, making them detectable by olfactory means. A large leak can be detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are common and in place in industry.

Proper facility design and construction – A key element in the control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. For example, a valve that has been manufactured under high quality conditions can be expected to have lower runout on the valve stem, and the valve stem is typically polished to a smoother surface. Both of these factors greatly reduce the likelihood of leaking. A second element affecting fugitive emissions is optimization of the number and type of components in the facility.

Replace rod packing on reciprocating compressors as required by NSPS OOOO – NSPS OOOO requires the replacement of rod packing on reciprocating compressors in order to reduce VOC emissions. This measure should also reduce GHG fugitive emissions from affected compressors.

Table 4 summarizes the control technologies selected as potential GHG BACT candidates.

TABLE 4
POTENTIAL CONTROL TECHNOLOGIES

Emission Unit Group	Potential Technology
Compressor Engines	Natural Gas as Fuel
	Good Combustion, Operations, and Maintenance Practices in accordance with 40 CFR 60 Subpart JJJJ
	Air/Fuel Ratio Controllers
	Efficient Engine Design
	Electric Powered Compression
Hot Oil Heaters, Regeneration Heaters	Natural Gas as Fuel
	Good Combustion, Operations, and Maintenance Practices
	Combustion Air Controls
	Fuel Gas Pre-heater / Air Pre-heater
	Efficient Heater Design
Amine Still Vents	Natural Gas as Fuel
	Good Combustion, Operations, and Maintenance Practices
	Carbon Capture and Sequestration
	Thermal Oxidizer
	Flare
	Flash Tank Gas Recovery
	Condenser
Regenerative Thermal Oxidizers (RTOs)	Natural Gas as Fuel
	Good Combustion, Operations, and Maintenance Practices
	Proper Design
Fugitives	Install sealed or leakless components
	Install Pneumatic controllers that comply with NSPS OOOO
	Implement NSPS OOOO LDAR programs as required
	Implement an alternate monitoring program using remote sensing
	Implement an audio/visual/olfactory (AVO) monitoring program for odorous compounds
	Proper facility design and construction
	Replace rod packing on reciprocating compressors as required by NSPS OOOO

4.2 Step 2 Eliminate Technically Infeasible Control Options

Step 2 of the top-down approach allows for the elimination of control options that are technically infeasible. In addition, each technology is either identified as "demonstrated" (that is it has been previously installed and operated successfully on a similar facility); or if undemonstrated, then a determination was made as to whether the technology is both "available" and "applicable." Technologies identified in Step 1 that are neither demonstrated nor found to be both available and applicable are eliminated under Step 2.

The results of Step 2 are summarized in Table 5 Below

TABLE 5
POTENTIAL CONTROL TECHNOLOGIES

Unit Group	Potential Technology	Feasible (Yes/No)	Demon-strated (Yes/No)	Available & Applicable (Yes/No)	Eliminated (Yes/No)
Compressor Engines	Natural Gas as Fuel	Yes	Yes	Yes	No
	Good Combustion, Operations, and Maintenance Practices	Yes	Yes	Yes	No
	Air/Fuel Ratio Controllers	Yes	Yes	Yes	No
	Efficient Engine Design	Yes	Yes	Yes	No
	Electric Powered Compression	No. Grid electric supply not adequate	Yes	No	Yes
Hot Oil Heaters, Regeneration Heaters	Natural Gas as Fuel	Yes	Yes	Yes	No
	Good Combustion, Operations, and Maintenance Practices	Yes	Yes	Yes	No
	Combustion Air Controls	Yes	Yes	Yes	No
	Fuel Gas Pre-heater / Air Pre-heater	Partial. Not feasible <50 MMBtu/hr[1]	Yes	Yes	No
	Efficient Heater Design	Yes	Yes	Yes	No
Amine Still Vents	Natural Gas as Fuel	Yes	Yes	Yes	No
	Good Combustion, Operations, and Maintenance Practices	Yes	Yes	Yes	No
	Carbon Capture and Sequestration	Yes	Yes	Yes, up to 7 MMSCF/D	No
	Thermal Oxidizer	Yes	Yes	Yes	No
	Flare	Yes	Yes	Yes	No

Unit Group	Potential Technology	Feasible (Yes/No)	Demon-strated (Yes/No)	Available & Applicable (Yes/No)	Eliminated (Yes/No)
	Flash Tank Gas Recovery	Yes	Yes	Yes	No
	Condenser	Yes	Yes	Yes	No
RTO	Natural Gas as Fuel	Yes	Yes	Yes	No
	Good Combustion, Operations, and Maintenance Practices	Yes	Yes	Yes	No
	Proper Design	Yes	Yes	Yes	No
Fugitives	Install sealed or leakless components	No, Leakless components have variable useful life and cannot be repaired without unit shutdown[2].	Yes	Yes	Yes
	Install Pneumatic controllers that comply with NSPS OOOO	Yes	Yes	Yes	No
	Implement NSPS OOOO LDAR programs as required	Yes	Yes	Yes	No
	Implement an alternate monitoring program using remote sensing	Yes	Yes	Yes	No
	Implement an audio/visual/olfactory (AVO) monitoring program	Yes	Yes	Yes	No
	Proper facility design and construction	Yes	Yes	Yes	No
	Replace rod packing on reciprocating compressors as required by NSPS OOOO	Yes	Yes	Yes	No

1 - Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry (EPA, Office of Air and Radiation, October 2010), Section 3.0 Summary of GHG Reduction Measures and Table 1 Summary of GHG Reduction Measures for the Petroleum Refinery Industry. (Appendix A)

2 - Calpine Corp Statement of Basis for Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for Channel Energy Center (CEC), LLC. EPA Region 6. August 2012. (Appendix A)

4.3 Step 3 Rank Remaining Control Technologies

Step 3 of the top-down approach involves ranking the remaining control technologies based on control effectiveness including:

- Control effectiveness for each regulated NSR pollutant (% pollutant removed)
- Expected emission rate for each regulated NSR pollutant (tons per year)
- Expected emission reduction for each regulated NSR pollutant (tons per year)
- Output based emissions limits (e.g. grams per horsepower hour (g/hp-hr)).

The results of the technology ranking are provided in Table 6 below:

TABLE 6
RANKING CONTROL TECHNOLOGIES

Unit Group	Potential Technology	Typical Control Efficiency-Pollutant Removal (%)	Estimated Uncontrolled CO_2e Emission Rate (TPY)	Expected CO_2e Emission Reduction (TPY)	Emission Limit	Ranking
Compressor Engines	Natural Gas as Fuel	10%	335,004	33,500	18,914 TPY of CO_2e per engine	1
	Good Combustion, Operations, and Maintenance Practices	1-10%		16,750		2
	Air/Fuel Ratio Controllers					
	Efficient Engine Design					
Hot Oil Heaters, Regeneration Heaters	Fuel Gas Pre-heater / Air Pre-heater	10-15%	177,035	21,244	Good Combustion and Maintenance Practices[1]	1
	Natural Gas as Fuel	10%		17,704		2
	Good Combustion, Operations, and Maintenance Practices	1-10%		8,852		3
	Efficient Heater Design	1-10%		8,852		4
	Combustion Air Controls	1-3%		3,541		5
Amine Still Vents	Carbon Capture and Sequestration	42% of emissions after other controls, 35% of uncontrolled emissions	393,265	137,091	Up to 7 MMSCF/D of Acid Gas will transferred to the proposed Kinder Morgan facility each day that both facilities are in operation	1
	Natural Gas as Fuel	10%		39,326	120 Lbs CO_2e per thousand standard cubic feet of acid gas vented through an RTO.	2
	Good Combustion, Operations, and Maintenance Practices	1-10%		19,663		3
	Condenser	<1%		1,966		4

Unit Group	Potential Technology	Typical Control Efficiency-Pollutant Removal (%)	Estimated Uncontrolled CO_2e Emission Rate (TPY)	Expected CO_2e Emission Reduction (TPY)	Emission Limit	Ranking
	Flash Tank Gas Recovery	<1%		1,966		5
	Thermal Oxidizer	Emissions have lower GWP		NA		6
	Flare	Emissions have lower GWP		NA		7
RTO	Natural Gas as Fuel	10%	27	3	Good Combustion and Maintenance Practices	1
	Proper Design	1-10%		1		2
	Good Combustion, Operations, and Maintenance Practices	1-3%		1		3
Fugitives	Pneumatic controllers comply with NSPS OOOO	97%	2,030	15	Compliance with NSPS Subpart OOOO	1
	Implement an alternate monitoring program using remote sensing	97%		1,970		2
	Implement NSPS OOOO LDAR programs as required	75-93%		1,523		3
	Implement an audio/visual/olfactory (AVO) monitoring program	70-90%				4
	Replace rod packing on reciprocating compressors as required by NSPS OOOO	80%		25		5
	Proper facility design and construction	ND		ND		6

1 – Draft BACT Determination LA-0271 (draft)

4.4 Step 4 Evaluate Most Effective Controls and Eliminate Control Options Based on Collateral Impacts

Step 4 of the top-down approach eliminates control options based on collateral impacts. In descending order of the control rankings identified in Step 3, the collateral impacts of each control option were evaluated and compared. In particular the following items were considered:

- Energy impacts (efficiency, BTU, kWh)
- Solid or hazardous waste
- Water discharge from control device
- Emissions of air toxics and other non-NSR regulated pollutants
- Other environmental impacts
- Economic impacts (e.g., total cost effectiveness, incremental cost effectiveness)

Table 7 summarizes the results of Step 4:

TABLE 7
COLLATERAL IMPACTS OF CONTROL TECHNOLOGIES

Unit Group	Potential Technology	Energy Impacts	Environmental Impacts	Economic Cost ($/Ton)	Eliminate (Yes/No)
Compressor Engines	Natural Gas as Fuel	No	No	Not determined, all technologies adopted	No
	Good Combustion, Operations, and Maintenance Practices	No	No		No
	Air/Fuel Ratio Controllers	No	No		No
	Efficient Engine Design	No	No		No
Hot Oil Heaters, Regeneration Heaters	Fuel Gas Pre-heater / Air Pre-heater	Yes. Fans required	Yes. Typically increases NOx emissions	Not determined	Yes
	Natural Gas as Fuel	No	No	Not determined, technologies adopted	No
	Good Combustion, Operations, and Maintenance Practices	No	No		No
	Efficient Heater Design	No	No		No
	Combustion Air Controls	No	No		No
Amine Still Vents	Carbon Capture and Sequestration	Yes	Yes	Feasible up to 7 MMSCF/D. Additional volumes economically infeasible	Partial. A maximum of 7 MMSCF/D of CO_2 controlled

Unit Group	Potential Technology	Energy Impacts	Environmental Impacts	Economic Cost ($/Ton)	Eliminate (Yes/No)
	Natural Gas as Fuel	No	No	Not determined, all technologies adopted	No
	Good Combustion, Operations, and Maintenance Practices	No	No		No
	Condenser	Yes	No		No
	Flash Tank Gas Recovery	No	No		No
	Thermal Oxidizer	No	No		No
	Flare	Yes	Yes	Not determined	Yes
RTO	Natural Gas as Fuel	No	No	Not determined, all technologies adopted	No
	Proper Design	No	No		No
	Good Combustion, Operations, and Maintenance Practices	No	No		No
Fugitives	Pneumatic controllers comply with NSPS OOOO	No	No	Not determined	No
	Implement an alternate monitoring program using remote sensing	No	No	$ 1,795[1]	Yes
	Implement NSPS OOOO LDAR programs as required	No	No	Not determined, technologies adopted	No
	Implement an audio/visual/olfactory (AVO) monitoring program	No	No		No
	Replace rod packing on reciprocating compressors every 26,000 hours as required by NSPS OOOO	No	No		No
	Proper facility design and construction	No	No		No

1 – Cost effectiveness for methane, Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution (EPA-435/R-11-002, July 2011). Table 8-18

4.4.1 Discussion of Limited Technologies - CCS for Amine Still Vents

CO_2 Capture and Sequestration has energy, environmental and economic impacts that limit its use as a control option for the Ramsey Gas Plant. These impacts are described briefly below.

The first issue to address is the destination of the capture CO_2. There are three options that have been deemed potentially feasible:

- Sequestration in a geological formation
- Use in Enhanced Oil Recovery (EOR)
- Transportation to an existing CO_2 pipeline

A study of the risks associated with long-term geologic storage of CO_2 places those risks on par with the underground storage of natural gas or acid-gas. However the specific liabilities associated with underground CO_2 storage are less well characterized and understood. A recent publication from MIT states that "The characteristics (of long term CO_2 storage) pose a challenge to a purely private solution to liability" (de Figueiredo, M., 2007. The Liability of Carbon Dioxide Storage, PhD. Thesis, MIT Engineering). The liability associated with sequestration in geologic formations and long-term environmental impact uncertainty remove this CCS option from further consideration.

The Ramsey Plant is located within a few hundred feet of an existing 4-inch diameter Kinder Morgan CO_2 pipeline lateral that was originally installed to deliver CO_2 for an enhanced oil recovery (EOR) project. The line is currently inactive. This particular lateral is connected to Kinder Morgan's main pipeline network which transports CO_2 for various uses, including EOR. Therefore the evaluation of transporting produced CO_2 to the Kinder Morgan pipeline network addresses both the options of transportation to an existing pipeline and use of the gas for EOR. Transporting CO_2 gas to the Kinder Morgan pipeline has been reported to be technically feasible in theory for similar facilities located in the region of the Ramsey Plant, but no such transfer arrangement has been made public.

Nuevo has entered discussions with Kinder Morgan regarding treatment and transportation of CO_2 from the amine vent stream at the Ramsey Plant. By the time Ramsey IV Plant is scheduled to start operations, the Kinder Morgan system is planned to have capacity to potentially accept up to 7 MMSCF/D of CO_2 from the Ramsey Plant. This represents the majority of the acid gas anticipated to be generated by Amine Still Vent A-4 and approximately 42% of the designed maximum amine vent gas production rate from the proposed expansion. Kinder Morgan has proposed to build a facility located adjacent to the Ramsey Plant to treat 7 MMSCF/D of amine still vent acid gas generated at the Ramsey Plant and transport it to their pipeline system. Nuevo does not have access to operating cost data for the proposed Kinder Morgan facility and so is unable to estimate the cost of control for CCS.

Demand for CO_2 and the capacity of the Kinder Morgan pipeline system may change due to factors beyond Nuevo's control. Such changes may either reduce the amount of CO_2 that can be transferred to Kinder Morgan or increase pipeline system capacity so that additional acid gas generated by planned Amine Still Vent A-5 can also be transferred in the future. Any amine unit vent gas that cannot be taken or treated by Kinder Morgan will be controlled by the Ramsey Plant RTO units. For purposes of emission estimation, this application assumes that 42% of the CO_2 produced by the amine units at the Ramsey Plant will be transferred to Kinder Morgan. However, the actual amount of acid gas transferred on any given day may vary based on circumstances beyond Nuevo's control.

Some of the CO_2e emission reductions reported in this application may be offset by CO_2e emissions from the Kinder Morgan processing plant. Nuevo does not have access to the data necessary to estimate CO_2e emissions from the proposed Kinder Morgan facility.

Based on this analysis, Nuevo concludes that CCS is an economically feasible control technology option for up to 7 MMSCF/D of CO_2 from the Ramsey Plant. According to analyses presented by proponents of a nearby facility (See Application for Prevention of Significant Deterioration for Greenhouse Gas Emissions Delaware Basin]V Gathering LLC, Avalon Mega CCF, Loving County, Texas, January 22, 2013, Appendix A) it is not economically feasible to treat and transport produced CO_2 a distance of 12 miles. The next nearest CO_2 pipeline system is located approximately 30 miles from the Ramsey Plant site, more than twice the distance determined to be infeasible. No other potential recipients for produced CO_2 have been identified. Based on the information available, CCS of amounts of CO_2 exceeding 7 MMSCF/D is not economically feasible.

4.4.2 Discussion of Eliminated Technologies - Flare for Amine Still Vents

The use of a flare as a control device for the amine still vents was eliminated in favor of an RTO because a flare would cause higher GHG emissions than the alternative thermal oxidizer. A flare would use additional fuel, including pilot fuel, than the proposed thermal oxidizer; and would provide slightly less efficient control of methane emissions. A flare would also yield additional environmental impacts because of slightly lower estimated control efficiency for VOC and HAPs than a thermal oxidizer.

4.4.3 Discussion of Eliminated Technologies - Fuel Gas Pre-heater / Air Pre-heater for Proposed Hot Oil Heaters

Combustion air and fuel gas preheating was eliminated because of adverse environmental impacts and increased energy consumption that would cause additional GHG emissions. The flue gases of a process heater can be used to preheat the combustion air of fuel gas. Every 35 °F drop in exit flue gas temperature increases the thermal efficiency of the heater by 1 percent. The resulting fuel savings can range from 8-18 percent, and yield GHG reductions conservatively estimated at 5-15 percent. Air preheating would require a natural draft system to be converted to a forced draft system requiring installation of fans, which would increase electricity consumption. Increased energy consumption would at least partially offset GHG reductions obtained by preheating.

Fuel or air preheating typically raises combustion temperature, counteracting NO_X controls and typically increasing NO_X emissions. Increased NO_X emissions due to preheating systems threaten to prevent the source on which they are installed from meeting required BACT emission limits. Air preheaters are contraindicated at facilities like the Ramsey Plant that are required to meet BACT emission limits for criteria pollutants.

4.4.4 Discussion of Eliminated Technologies - Implement an alternate monitoring program using remote sensing

An alternate monitoring program using remote sensing was eliminated because of excessively high costs, especially given the relatively small amount of GHG that could be controlled by this technology. Total fugitive GHG emissions from the Ramsey Plant are estimated to be less than 500 tons of CO_2e. According to the EPA publication Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution (EPA-435/R-11-002, July 2011), control costs for alternate monitoring programs using remote sensing are expected to be $ 1,795 per ton for methane, the main GHG in fugitive emission and so alternate monitoring is not cost effective for GHG control.

4.5 Step 5 Select GHG BACT

Step 5 involves selecting the most effective control alternative not eliminated in Step 4 for each parameter under consideration which then establishes the corresponding emission limit. The selected BACT and associated emission limits for each source and affected pollutant are summarized in Table 8 below.

TABLE 8
SELECTED BACT TECHNOLOGIES AND BACT EMISSION RATE

Emission Unit	Control Technology	Proposed BACT Emission Limit	Proposed Compliance Demonstration
Compressor Engines	Natural Gas as Fuel	18,914 TPY of CO_2e per engine	See Table 9
	Good Combustion, Operations, and Maintenance Practices		
	Air/Fuel Ratio Controllers		Comply with NSPS JJJJ and MACT ZZZZ
	Efficient Engine Design		
Hot Oil Heaters, Regeneration Heaters	Natural Gas as Fuel	Good Combustion and Maintenance Practices	See Table 9
	Good Combustion, Operations, and Maintenance Practices		
	Efficient Heater Design		
	Combustion Air Controls		
Amine Still Vents	CCS up to 7 MMSCF/D of CO_2	Up to 7 MMSCF/D of acid gas from Amine Unit Still Vents per day will be transferred to Kinder Morgan.	Record days when acid gas is transferred based on Ramsey Plant operating data
	Natural Gas as Fuel	219 Lbs CO_2e per thousand standard cubic feet of acid gas vented through an	See Table 9
	Good Combustion, Operations, and Maintenance Practices		
	Condenser		

Emission Unit	**Control Technology**	**Proposed BACT Emission Limit**	**Proposed Compliance Demonstration**
	Flash Tank Gas Recovery	RTO.	
	Thermal Oxidizer		
RTO	Natural Gas as Fuel	Good Combustion and Maintenance Practices	See Table 9
	Proper Design		
	Good Combustion, Operations, and Maintenance Practices		
Fugitives	Pneumatic controllers comply with NSPS OOOO	Compliance with NSPS Subpart OOOO	Comply with NSPS OOOO
	Implement NSPS OOOO LDAR programs as required		
	Implement an audio/visual/olfactory (AVO) monitoring program		
	Replace rod packing on reciprocating compressors every 26,000 hours as required by NSPS OOOO		
	Proper facility design and construction		

TABLE 9

SUMMARY OF PROPOSED GOOD COMBUSTION PRACTICES

Good Combustion Technique	Practice	Applicable Units	Compliance Demonstration Standard
Operator practices	• Documented operating procedures, updated as required for equipment or practice changes • Procedures include startup, shutdown, malfunction • Operating logs/record keeping.	All Combustion Units	• Maintain operating procedures as specified by equipment manufacturers. • Maintain logs or operating data.
Maintenance Knowledge	• Training on applicable equipment and procedures.	All Combustion Units	• Implement a maintenance training program.
Maintenance Practices	• Documented maintenance procedures, updated as required for equipment or practice changes • Routine evaluation, inspection, overhaul as appropriate for combustion equipment • Maintenance logs/record keeping.	All Combustion Units	• Maintain site specific procedures for best/optimum maintenance practices. • Schedule periodic evaluation, inspection, and overhaul as appropriate. • Maintain logs or operating data.
Firebox residence time, temperature, turbulence	• Residence time by design • Minimum combustion chamber temperature	RTOs	• Maintain design documentation.
Fuel quality analysis and fuel handling	• Monitor fuel quality • Fuel handling practices	Heaters, Amine Still Vents, RTOs	• Fuel analysis where composition could vary or maintain fuel quality documentation. • NSPS OOOO compliance. • Use plant residual gas as fuel except during periods of maintenance or equipment outage.
Combustion air distribution	• Adjustment of air distribution system based on visual observations • Adjustment of air distribution based on continuous or periodic monitoring.	Heaters, Amine Still Vents, RTOs	• Routine periodic adjustments and checks.

4.6 Site-wide GHG Minimization through Energy Efficiency

In addition to the top-down BACT analysis for selection of emission-source-specific control technologies for GHGs, EPA has also indicated that a site-wide evaluation of energy efficiency should take place as another means to minimize GHG emissions. In accordance with this guidance, overall energy efficiency was a basic design criterion in the selection of technologies and processing alternatives included in the proposed Ramsey Plant expansion.

The Ramsey Plant modification will be designed and constructed using new or updated energy efficient equipment. The plant was designed with heat and process integration in mind for increased energy efficiency. Where feasible, the facility will utilize available process streams to transfer heat and thereby reduce combustion heating requirements. Process vessels, piping, and components in hot and cold service to will be designed to conserve energy by preventing heat transfer to or from the atmosphere.

The facility will recycle the flash gas from the amine units through a low pressure compressor to the gas system instead of sending these vents to a control device. The recycling of this material will avoid the formation of additional GHG from combusting this material in a control device.

Process control instrumentation and pneumatic components will be operated using compressed air rather than fuel gas or off-gas; therefore, no GHG emissions will be emitted to the atmosphere from these components. The plant will be built using new, state-of-the-art equipment and process instrumentation and controls. It is Nuevo's operating and maintenance policy to maintain all equipment according to manufacturer specifications in order to maintain design operating efficiently.

5.0 GREEN HOUSE GAS EMISSION CALCULATION METHODS

The GHG emissions associated with the proposed Phase IV, V and VI expansion have been calculated. Summaries of these emissions are included in Section 2 of this application. Calculations can be found in the attachments in Section 4 of this application.

The calculations for the expansion are based on the following:

Compressor engine CO_2 and methane emissions were calculated using vendor supplied/guaranteed emission factors. The factors were provided by Caterpillar. Compressor engine N_2O emissions were calculated using an emission factor from 40 CFR 98, Table C-2 (Tier 1).

Heater and reboiler emissions were calculated using an emission factor from 40 CFR 98, Tables C-1 and C-2 (Tier 1).

The amine units' still vent emissions were calculated using ProMax 3.2. Up to 7 MMSCF/D of acid gas from the amine unit still vents will be transferred to an adjacent facility for processing and CO_2 recovery. The remaining acid gas will be vented through a RTO with 99% efficiency. Therefore 99% of the predicted VOC emissions were converted to CO_2 stoichiometrically by weight, and the GHG components of the remaining 1% were included in the calculated CO_2e amounts.

RTO emissions from fuel combustion were calculated using an emission factor from 40 CFR 98, Table C-1 (Tier 1).

Fugitive emissions were calculated using factors provided in Table 2-4, Oil and Gas Production Operations Average Emission factors, 1995 Protocol for Equipment Leak Emission Estimates, EPA-4J3/R-95-017

Maintenance/blow down emissions were based on an average of two (2) compressor blow down events/month for each new compressor, assuming a worst case volume release.

6.0 OTHER FEDERAL AGENCY REVIEWS

Since the GHG PSD is being reviewed by the EPA, a federal agency, EPA is required to ensure that the project will not have adverse effects on other federal interest areas. The specific areas that this project may impact are threatened and endangered species and cultural resources.

Threatened and endangered species in Texas is under the jurisdiction of the U.S. Fish and Wildlife Services and the Texas Department of Parks and Wildlife. A review of these entities' websites indicate that the potentially endangered species are: the Least Tern, the Northern Aplomado Falcon, the Black-footed Ferret, the Grey Wolf, Pecos Assiminea Snail, and Phantom Tryonia.

Cultural resources in Texas are under the jurisdiction of the State Historic Preservation Officer (SHPO), which is under the Texas Historical Commission.

Reports are being completed and will be sent to the appropriate agencies for comments and clearance. Both the reports and the comments will be sent to EPA under separate cover.

SECTION 2.0

ESTIMATED CO_2e POTENTIAL TO EMIT (PTE) EMISSIONS USING 40 CFR 98 EMISSION FACTORS

Facility: Ramsey Gas Plant

Source Category	Potential CO_2e Lbs /Hour	Potential CO_2e TPY
Engines	94,883	297,218
RTO	45,993	193,275
Heaters and Reboilers	26,677	116,843
Fugitives	107	467
Totals	**167,660**	**607,803**

ESTIMATED CO2e POTENTIAL TO EMIT (PTE) EMISSIONS USING MANUFACTURER DATA AND 40 CFR 98 EMISSION FACTORS

Facility: Ramsey Gas Plant

		Rating			Heat Input	Emission Factors		
Compressor Engines		**hp**	**Fuel Factor**	**Hours of Operation**	**Maximum (MMBtu /yr)**	**CO_2**	**CH_4**	**N_2O**
EPN			Btu/bhp-hr			g/bhp-hr[1]	g/bhp-hr[1]	kg/MMBtu[3]
C-15	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-16	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-17	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-18	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-19	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-20	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-21	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-22	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-23	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-24	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-25	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-26	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-27	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-28	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-29	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04

EMISSIONS

	CO_2	CH_4	N_2O	CO_2e	CO_2	CH_4	N_2O	CO_2e	
	lbs/hr	lbs/hr	lbs/hr	lbs/hr	TPY	TPY	TPY	TPY	
C-15	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-16	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-17	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-18	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-19	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-20	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-21	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-22	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-23	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-24	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-25	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-26	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-27	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-28	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-29	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
			SUBTOTAL	**67,290**			**SUBTOTAL**	**294,735**	**TPY**
Maintenance Startup and Shutdown (MSS) Emissions									
	6.55	1,103.47	0.000	**27,593**	0.59	99.31	0.000	**2,483**	
			TOTAL	**94,883**			**TOTAL**	**297,218**	**TPY**

1 Vendor Data

2 40 CFR 98 Table C-2 Emission Factor

3 40 CFR 98 Table C-2 Emission Factor

ESTIMATED CO_2e POTENTIAL TO EMIT (PTE) EMISSIONS USING 40 CFR 98 EMISSION FACTORS AND PROCESS DATA

Facility: Ramsey Gas Plant

Unit Description

Fuel Emissions	Heat Input Rating	Hours of Operation	Maximum (MMBtu /yr)	CO_2	CH_4	N_2O
	Heat Input			Emission Factors		
	MMBtu/hr			kg/MMBtu[1]	kg/MMBtu[2]	kg/MMBtu[2]
RTO-4	8	24	192	53.02	1.00E-03	1.00E-04
RTO-5	8	24	192	53.02	1.00E-03	1.00E-04

POTENTIAL EMISSIONS

	CO_2	CH_4	N_2O	CO_2e	CO_2	CH_4	N_2O	CO_2e
	lbs/hr	lbs/hr	lbs/hr	lbs/hr	TPY	TPY	TPY	TPY
RTO-4	935.1	0.02	0.002	**936**	11.2	0.0002	0.00002	**11**
RTO-5	935.1	0.02	0.002	**936**	11.2	0.0002	0.00002	**11**
			SUBTOTAL	**1,872** lbs/hr			**SUBTOTAL**	**22** TPY

Acid Gas Combustion Emissions

Acid Gas Flow Rate[3]

A-4	8.4	MMSCF/D
A-5	8.4	MMSCF/D
Total	16.8	MMSCF/D

Potential Amine Still Vent Acid Gas Combustion Emissions - 100% routed to for Control

	CO_2	CH_4	C_2H_6	C_3H_8	C_4H_{10}	C_5H_{12}	C_6H_{14}
A-4	37,594	31.63	19.93	9.82	4.73	0.76	0.82
A-5	37,594	31.63	19.93	9.82	4.73	0.76	0.82
Totals	75,189	63.25	39.86	19.65	9.45	1.53	1.64
Mole Weight	44.01	16.04	30.07	44.10	58.12	72.15	86.18
Mole Ratio	1	1	2	3	4	5	6
	Net CO_2 Emissions After Combustion, lbs.hr				Combustion Efficiency =		99.0%
	75,189	171.78	115.53	58.24	28.34	4.61	4.98

Facility: Ramsey Gas Plant

Unit Description

	Heat Input Rating	Hours of Operation	Heat Input Maximum (MMBtu /yr)	Emission Factors CO_2	CH_4	N_2O
	MMBtu /hr			kg/MMBtu[1]	kg/MMBtu[2]	kg/MMBtu[2]
H-8	36	8,760	315,360	53.02	1.00E-03	1.00E-04
H-9	60	8,760	525,600	53.02	1.00E-03	1.00E-04
H-10	36	8,760	315,360	53.02	1.00E-03	1.00E-04
H-11	60	8,760	525,600	53.02	1.00E-03	1.00E-04
H-12	36	8760	315,360	53.02	1.00E-03	1.00E-04

EMISSIONS

	CO_2	CH_4	N_2O	CO_2e	CO_2	CH_4	N_2O	CO_2e	
	lbs/hr	lbs/hr	lbs/hr	lbs/hr	TPY	TPY	TPY	TPY	
H-8	4,208	0.08	0.008	**4,212**	18,431	0.35	0.035	**18,450**	
H-9	7,013	0.13	0.013	**7,020**	30,718	0.58	0.058	**30,750**	
H-10	4,208	0.08	0.008	**4,212**	18,431	0.35	0.035	**18,450**	
H-11	7,013	0.13	0.013	**7,020**	30,718	0.58	0.058	**30,750**	
H-12	4,208	0.08	0.008	**4,212**	18,431	0.35	0.035	**18,450**	
			TOTAL	**26,677**	**lbs/hr**		**TOTAL**	**116,849**	**TPY**

1 40 CFR 98 Table C-1 Emission Factor

2 40 CFR 98 Table C-2 Emission Factor

ESTIMATED CO_2e POTENTIAL TO EMIT (PTE) EMISSIONS USING 40 CFR 98 EMISSION FACTORS

Facility: Ramsey Gas Plant

	EMISSIONS			
Fugitives	**CO_2**	**CH_4**	**N_2O**	**CO_2e**
	TPY	TPY	TPY	TPY
VALVES	2.29	18.31	0.000	**460**
PUMPS	0.09	0.7	0.000	**17**
FLANGES	0.39	3.1	0.000	**79**
OPEN LINES	0.00	0.00	0.000	**0**
RELIEF VALVES	0.23	1.85	0.000	**46**
COMPRESSORS	0.12	0.92	0.000	**23**
SAMPLE CONNECTIONS	0.17	1.39	0.000	**35**
			TOTAL	**556**

	CO_2	**CH_4**	**N_2O**	**CO_2e**	
Per Plant	1.10	8.76	0.00	185.28	tpy
	0.25	2.00	0.00	42.30	lbs/hr

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY
COMP-15	COMP-15	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	5.870	25.710
			N_2O	0.005	0.023
			CO_2e	3,584.000	15,698.000
COMP-16	COMP-16	Cat G3612 LE or equivalent	CO_2	4,486.000	19,649.000
			CH_4	5.870	25.710
			N_2O	0.005	0.023
			CO_2e	4,486.000	19,649.000
COMP-17	COMP-17	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	5.870	25.710
			N_2O	0.005	0.023
			CO_2e	4,486.000	19,649.000
COMP-18	COMP-18	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	5.870	25.710
			N_2O	0.005	0.023
			CO_2e	4,486.000	19,649.000
COMP-19	COMP-19	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	5.870	25.710
			N_2O	0.005	0.023
			CO_2e	4,486.000	19,649.000
COMP-20	COMP-20	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	5.870	25.710
			N_2O	0.005	0.023
			CO_2e	4,486.000	19,649.000
COMP-21	COMP-21	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	5.870	25.710
			N_2O	0.005	0.023
			CO_2e	4,486.000	19,649.000
COMP-22	COMP-22	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	5.870	25.710
			N_2O	0.005	0.023
			CO_2e	4,486.000	19,649.000
COMP-23	COMP-23	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	5.870	25.710
			N_2O	0.005	0.023
			CO_2e	4,486.000	19,649.000
			CO_2	3,435.736	15,048.525

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY
COMP-24	COMP-24	Cat G3612 LE or equivalent	CH_4	5.870	25.710
			N_2O	0.005	0.023
			CO_2e	4,486.000	19,649.000
COMP-25	COMP-25	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	5.870	25.710
			N_2O	0.005	0.023
			CO_2e	4,486.000	19,649.000
COMP-26	COMP-26	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	5.870	25.710
			N_2O	0.005	0.023
			CO_2e	4,486.000	19,649.000
COMP-27	COMP-27	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	5.870	25.710
			N_2O	0.005	0.023
			CO_2e	4,486.000	19,649.000
COMP-28	COMP-28	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	5.870	25.710
			N_2O	0.005	0.023
			CO_2e	4,486.000	19,649.000
COMP-29	COMP-29	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	5.870	25.710
			N_2O	0.005	0.023
			CO_2e	4,486.000	19,649.000
BD3	BD3	Engine blowdowns for Ramsey IV	CO_2	2.183	0.200
			CH_4	367.824	33.100
			N_2O	0.000	0.000
			CO_2e	9,197.780	827.800
BD4	BD4	Engine blowdowns for Ramsey V	CO_2	2.183	0.200
			CH_4	367.824	33.100
			N_2O	0.000	0.000
			CO_2e	9,197.780	827.800
BD5	BD5	Engine blowdowns for Ramsey VI Plants	CO_2	2.183	0.200
			CH_4	367.824	33.100
			N_2O	0.000	0.000
			CO_2e	9,197.780	827.800
H-8	H-8	36 MMBtu/hr or equivalent Regen Gas Heater	CO_2	4,207.964	18,430.883
			CH_4	0.079	0.347
			N_2O	0.008	0.035
			CO_2e	4,212.091	18,450.000

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY
H-9	H-9	60 MMBtu/hr or equivalent Hot Oil Heater	CO_2	7,013.274	30,718.138
			CH_4	0.132	0.578
			N_2O	0.013	0.058
			CO_2e	7,021.000	30,750.000
H-10	H-10	36 MMBtu/hr or equivalent Regen Gas Heater	CO_2	4,207.964	18,430.883
			CH_4	0.079	0.347
			N_2O	0.008	0.035
			CO_2e	4,212.091	18,450.000
H-11	H-11	60 MMBtu/hr or equivalent Hot Oil Heater	CO_2	7,013.274	30,718.138
			CH_4	0.132	0.578
			N_2O	0.013	0.058
			CO_2e	7,021.000	30,750.000
H-12	H-12	36 MMBtu/hr or equivalent Regen Gas Heater	CO_2	4,207.964	18,430.883
			CH_4	0.079	0.347
			N_2O	0.008	0.035
			CO_2e	4,212.091	18,450.000
RTO-4	RTO-4	Regenerative Thermal Oxidizer	CO_2	38,721.000	165,515.000
			CH_4	0.330	1.390
			N_2O	0.002	0.000
			CO_2e	38,729.000	165,543.793
RTO-5	RTO-5	Regenerative Thermal Oxidizer	CO_2	38,721.000	165,515.000
			CH_4	0.330	1.390
			N_2O	0.002	0.000
			CO_2e	38,729.000	165,543.793
FUG4	FUG4	Fugitive Emissions	CO_2	0.751	3.290
			CH_4	5.997	26.270
			N_2O	0.000	0.000
			CO_2e	126.935	556.000
FUG5	FUG5	Fugitive Emissions	CO_2	0.751	3.290
			CH_4	5.997	26.270
			N_2O	0.000	0.000
			CO_2e	126.935	556.000
FUG6	FUG6	Fugitive Emissions	CO_2	0.751	3.290
			CH_4	5.997	26.270
			N_2O	0.000	0.000
			CO_2e	126.935	556.000

Totals

	Lbs/hr	TPY
CO_2	156,687.550	678,097.746
CH_4	1,210.675	568.737
N_2O	0.132	0.560
CO_2e	198,498.418	742,872.986

SECTION 3.0

US EPA ARCHIVE DOCUMENT

TCEQ

TCEQ Use Only

TCEQ Core Data Form

For detailed instructions regarding completion of this form, please read the Core Data Form Instructions or call 512-239-5175.

SECTION I: General Information

1. Reason for Submission *(If other is checked please describe in space provided)*

☒ New Permit, Registration or Authorization *(Core Data Form should be submitted with the program application)*

☐ Renewal *(Core Data Form should be submitted with the renewal form)* ☐ Other

2. Attachments **Describe Any Attachments:** *(ex. Title V Application, Waste Transporter Application, etc.)*

☒Yes ☐No PSD Permit Application

3. Customer Reference Number *(if issued)*	Follow this link to search for CN or RN numbers in Central Registry**	4. Regulated Entity Reference Number *(if issued)*
CN 604322891		RN 100228899

SECTION II: Customer Information

5. Effective Date for Customer Information Updates (mm/dd/yyyy) 1/1/2014

6. Customer Role (Proposed or Actual) – *as it relates to the Regulated Entity listed on this form. Please check only one of the following:*

☐Owner ☐ Operator ☒ Owner & Operator

☐Occupational Licensee ☐ Responsible Party ☐ Voluntary Cleanup Applicant ☐Other: ____________

7. General Customer Information

☐ New Customer ☒ Update to Customer Information ☐ Change in Regulated Entity Ownership

☐Change in Legal Name (Verifiable with the Texas Secretary of State) ☐ No Change**

If "No Change" and Section I is complete, skip to Section III – Regulated Entity Information.

8. Type of Customer:	☒ Corporation	☐ Individual	☐ Sole Proprietorship- D.B.A
☐ City Government	☐ County Government	☐ Federal Government	☐ State Government
☐ Other Government	☐ General Partnership	☐ Limited Partnership	☐ Other: ____________

9. Customer Legal Name *(If an individual, print last name first: ex: Doe, John)*	*If new Customer, enter previous Customer below*	*End Date:*
Nuevo Midstream, LLC		

10. Mailing Address:							
	1221 Lamar, Suite 1100						
	City	Houston	**State**	TX	**ZIP**	77010	**ZIP + 4**

11. Country Mailing Information *(if outside USA)*	**12. E-Mail Address** *(if applicable)*

13. Telephone Number	**14. Extension or Code**	**15. Fax Number** *(if applicable)*
( ) -		( ) -

16. Federal Tax ID *(9 digits)*	**17. TX State Franchise Tax ID** *(11 digits)*	**18. DUNS Number** *(if applicable)*	**19. TX SOS Filing Number** *(if applicable)*

20. Number of Employees	**21. Independently Owned and Operated?**
☐ 0-20 ☐ 21-100 ☐ 101-250 ☐ 251-500 ☐ 501 and higher	☐ **Yes** ☐ **No**

SECTION III: Regulated Entity Information

22. General Regulated Entity Information *(If 'New Regulated Entity" is selected below this form should be accompanied by a permit application)*

☐ New Regulated Entity ☐ Update to Regulated Entity Name ☐ Update to Regulated Entity Information ☒ No Change** *(See below)*

****If "NO CHANGE" is checked and Section I is complete, skip to Section IV, Preparer Information.**

23. Regulated Entity Name *(name of the site where the regulated action is taking place)*

24. Street Address of the Regulated Entity: *(No P.O. Boxes)*							
	City		State		ZIP		ZIP + 4

25. Mailing Address:							
	City		State		ZIP		ZIP + 4

26. E-Mail Address:			
27. Telephone Number	**28. Extension or Code**	**29. Fax Number** *(if applicable)*	
( ) -		( ) -	
30. Primary SIC Code (4 digits)	**31. Secondary SIC Code** (4 digits)	**32. Primary NAICS Code** (5 or 6 digits)	**33. Secondary NAICS Code** (5 or 6 digits)
34. What is the Primary Business of this entity? *(Please do not repeat the SIC or NAICS description.)*			

Questions 34 – 37 address geographic location. Please refer to the instructions for applicability.

35. Description to Physical Location:					
36. Nearest City		**County**	**State**		**Nearest ZIP Code**
37. Latitude (N) In Decimal:			**38. Longitude (W) In Decimal:**		
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds

39. TCEQ Programs and ID Numbers Check all Programs and write in the permits/registration numbers that will be affected by the updates submitted on this form or the updates may not be made. If your Program is not listed, check other and write it in. See the Core Data Form instructions for additional guidance.

☐ Dam Safety	☐ Districts	☐ Edwards Aquifer	☐ Industrial Hazardous Waste	☐ Municipal Solid Waste
☐ New Source Review – Air	☐ OSSF	☐ Petroleum Storage Tank	☐ PWS	☐ Sludge
☐ Stormwater	☐ Title V – Air	☐ Tires	☐ Used Oil	☐ Utilities
☐ Voluntary Cleanup	☐ Waste Water	☐ Wastewater Agriculture	☐ Water Rights	☐ Other:

SECTION IV: Preparer Information

40. Name:	Alison Doyle	41. Title:	Project Manager
42. Telephone Number	**43. Ext./Code**	**44. Fax Number**	**45. E-Mail Address**
(713) 973-6085		(713) 973-6087	adoyle@ses-inc.net

SECTION V: Authorized Signature

46. By my signature below, I certify, to the best of my knowledge, that the information provided in this form is true and complete, and that I have signature authority to submit this form on behalf of the entity specified in Section II, Field 9 and/or as required for the updates to the ID numbers identified in field 39.

(See the Core Data Form instructions for more information on who should sign this form.)

Company:	Nuevo Midstream, LLC	Job Title:	Vice President Operations
Name*(In Print)*:	Dwight D. Serrett	**Phone:**	(713) 337-6510
Signature:	Dwight D. Serrett	**Date:**	1/14/2014

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

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

I. Applicant Information		
A. Company or Other Legal Name: Nuevo Midstream LLC		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: Dwight Serrett		
Title: Vice President Operations		
Mailing Address: 1331 Lamar, Suite 1450		
City: Houston	State: TX	ZIP Code: 77010
Telephone No.: 713-756-1621	Fax No.: 713-759-0805	E-mail Address:ds@nuevomidstream.com
C. Technical Contact Name: Clint Cone		
Title: System Superintendent		
Company Name: Nuevo Midstream LLC		
Mailing Address: P.O. Box 9		
City: Malaga	State: NM	ZIP Code: 88263
Telephone No.:432-273-0010	Fax No.: 432-273-0027	E-mail Address: cc@nuevomidstream.com
D. Site Name: Ramsey Gas Plant		
E. Area Name/Type of Facility:		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Gas Treating and Compression		
Principal Standard Industrial Classification Code (SIC): 1321		
Principal North American Industry Classification System (NAICS): 211112		
G. Projected Start of Construction Date: August 1, 2014		
Projected Start of Operation Date: December 1, 2014		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address:231 CR 452		
City/Town: Orla	County: Reeves	ZIP Code: 79770
Latitude (nearest second):31:55:34.72	Longitude (nearest second): -104:01:19.61	

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

I.	**Applicant Information (continued)**	
I.	Account Identification Number (leave blank if new site or facility): RF-0006-T	
J.	Core Data Form.	
Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L). *change of customer address*		☒ YES ☐ NO
K.	Customer Reference Number (CN): CN604322891	
L.	Regulated Entity Number (RN): RN100228899	
II.	**General Information**	
A.	Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.	☐ YES ☒ NO
B.	Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES ☒ NO
C.	Number of New Jobs: 15-20	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: Carlos I Uresti		District No.:19
State Representative: Pancho Nevarez		District No.:74
III.	**Type of Permit Action Requested**	
A.	Mark the appropriate box indicating what type of action is requested.	
☒ Initial ☐ Amendment ☐ Revision (30 TAC 116.116(e) ☐Change of Location ☐ Relocation		
B.	Permit Number (if existing): O3546	
C.	Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)*	
☒ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit		
☒ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source		
☐ Other:		
D.	Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

III. Type of Permit Action Requested *(continued)*			
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.0			☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO", attach detailed information.			☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?			☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.			
List: Standard Permit Registration Permit # 101511			
Title V Permit #: O3546			
G. Are you permitting planned maintenance, startup, and shutdown emissions? If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.			☒ YES ☐ NO
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) Is this facility located at a site required to obtain a federal operating permit? If Yes, list all associated permit number(s), attach pages as needed).		☐ YES ☒ NO ☐ To be determined	
Associated Permit No (s.):			
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.			
☐ FOP Significant Revision	☐ FOP Minor	☐ Application for an FOP Revision	
☐ Operational Flexibility/Off-Permit Notification		☐ Streamlined Revision for GOP	
☐ To be Determined		☒ None	

III. Type of Permit Action Requested *(continued)*		
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*		
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***		
☒ GOP Issued	☐ GOP application/revision application submitted or under APD review	
☐ SOP Issued	☐ SOP application/revision application submitted or under APD review	
IV. Public Notice Applicability		
A. Is this a new permit application or a change of location application?		☒ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.		☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?		☒ YES ☐ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?		☒ YES ☐ NO
If Yes, list the affected state(s) and/or Class I Area(s).		
List: New Mexico		
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.		
1. Is there any change in character of emissions in this application?		☐ YES ☐ NO
2. Is there a new air contaminant in this application?		☐ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?		☐ YES ☐ NO
F. List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***		
Volatile Organic Compounds (VOC): 116.01 tpy		
Sulfur Dioxide (SO2): 190.62 tpy		
Carbon Monoxide (CO):276.63 tpy		
Nitrogen Oxides (NOx): 510.96 tpy		
Particulate Matter (PM): 25.95 tpy		
PM 10 microns or less (PM10): 12.54 tpy		
PM 2.5 microns or less (PM2.5): 12.54 tpy		
Lead (Pb): N/A		
Hazardous Air Pollutants (HAPs): 20.30		
Other speciated air contaminants not listed above: HCHO: 18.62 tpy		

TCEQ

V. Public Notice Information *(complete if applicable)*		
A. Public Notice Contact Name: Alison Doyle		
Title: Sound Environmental Solutions, Inc. (SES), Project Manager		
Mailing Address: 11111 Katy Freeway, Suite 1004		
City: Houston	State: TX	ZIP Code: 77079
B. Name of the Public Place: Reeves County Library		
Physical Address *(No P.O. Boxes)*: 505 S. Park St.		
City: Pecos	County: Reeves	ZIP Code: 79772
The public place has granted authorization to place the application for public viewing and copying.		☒ YES ☐ NO
The public place has internet access available for the public.		☒ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable:		
Mailing Address:		
City:	State:	ZIP Code:
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. Add a second page		
Chief Executive:		
Mailing Address:		
City:	State:	ZIP Code:
Name of the Indian Governing Body:		
Mailing Address:		
City:	State:	ZIP Code:

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

V. Public Notice Information *(complete if applicable) (continued)*		
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. *(continued)*		
Name of the Federal Land Manager(s):		
D. Bilingual Notice		
Is a bilingual program required by the Texas Education Code in the School District?		☒ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?		☒ YES ☐ NO
If Yes, list which languages are required by the bilingual program?	Spanish	
VI. Small Business Classification *(Required)*		
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?		☒ YES ☐ NO
B. Is the site a major stationary source for federal air quality permitting?		☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?		☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?		☐ YES ☒ NO
VII. Technical Information		
A. The following information must be submitted with your Form PI-1 ***(this is just a checklist to make sure you have included everything)***		
1. ☒ Current Area Map – Figure 1		
2. ☒ Plot Plan		
3. ☐ Existing Authorizations		
4. ☒ Process Flow Diagram – **Figure 3**		
5. ☒ Process Description –**2.0 in Section 1, Introduction**		
6. ☐ Maximum Emissions Data and Calculations		
7. ☒ Air Permit Application Tables		
a. ☒ Table 1(a) (Form 10153) entitled, Emission Point Summary		
b. ☐ Table 2 (Form 10155) entitled, Material Balance – N/A		
c. ☐ Other equipment, process or control device tables		
B. Are any schools located within 3,000 feet of this facility?		☐ YES ☒ NO

VII. **Technical Information**			
C. Maximum Operating Schedule:			
Hour(s):24	Day(s): 7	Week(s):52	Year(s): 8760
Seasonal Operation? If Yes, please describe in the space provide below.			☐ YES ☒ NO
D. Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☒ YES ☐ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.			
Planned MSS: Engine blowdowns			
Year(s) MSS included in emission inventory: 2012			
E. Does this application involve any air contaminants for which a disaster review is required?			☐ YES ☒ NO
F. Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?			☐ YES ☒ NO
VIII. **State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*			
A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?			☒ YES ☐ NO
B. Will emissions of significant air contaminants from the facility be measured?			☒ YES ☐ NO
C. Is the Best Available Control Technology (BACT) demonstration attached?			☒ YES ☐ NO
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?			☒ YES ☐ NO
IX. **Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*			
A. Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?			☒ YES ☐ NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?			☒ YES ☐ NO

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☒ YES ☐ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
Is the estimated capital cost of the project greater than $2 million dollars?		☒ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E. **Following this form**		
XI.	**Permit Fee Information**	
Check, Money Order, Transaction Number ,ePay Voucher Number:		Fee Amount: $75,000.00
Paid online?		☒ YES ☐ NO
Company name on check:		
Is a copy of the check or money order attached to the original submittal of this application?		☒ YES ☐ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached? **Have paid maximum permit fee of $75,000.00**		☐ YES ☒ NO ☐ N/A

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XII. Delinquent Fees and Penalties
This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.

XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: Dwight D. Serrett
Signature: Dwight D Serrett *Original Signature Required*
Date: ~~July 31, 2013~~ January 14, 2014 ABD for DDS

FORM PI-1 SECTION X
PROFESSIONAL ENGINEER (P.E.) SEAL

I, Rachel Pappworth, have reviewed the following sections of the attached application for a Prevention of Significant Deterioration (PSD) permit submitted by Sound Environmental Solutions, Inc:

Emissions Data

Best Available Control Technology

The capital cost of the project is estimated to be greater than $25,000.00

The application for a PSD permit, as referenced above, was reviewed on the 21st day of January 2014

Signed: SS R Pappworth

Date 1/21/2014

Professional Engineer Registration Number: 76885

B Texas Commission on Environmental Quality
Form OP-ACPS
Application Compliance Plan and Schedule

Date:01/14/2014	**Regulated Entity No.:100228899**	**Permit No.:O3546**
Company Name: Nuevo Midstream, LLC	**Area Name: Ramsey Gas Plant**	

- Part 1 of this form must be submitted with all initial FOP applications and renewal applications.
- The Responsible Official must use Form OP-CRO1 (Certification by Responsible Official) to certify information contained in this form in accordance with 30 TAC § 122.132(e)(9).

Part 1

A.	**Compliance Plan — Future Activity Committal Statement**

The *Responsible Official* commits, utilizing reasonable effort, to the following:
As the responsible official it is my intent that all emission units shall continue to be in compliance with all applicable requirements they are currently in compliance with, and all emission units shall be in compliance by the compliance dates with any applicable requirements that become effective during the permit term.

B.	**Compliance Certification — Statement for Units in Compliance*** **(Indicate response by entering an "X" in the appropriate column)**	
1.	With the exception of those emission units listed in the Compliance Schedule section of this form (Part 2, below), and based, at minimum, on the compliance method specified in the associated applicable requirements, are all emission units addressed in this application in compliance with all their respective applicable requirements as identified in this application?	☒ YES ☐ NO
2.	Are there any non-compliance situations addressed in the Compliance Schedule Section of this form (Part 2)?	☒ YES ☐ NO
3.	If the response to Item B.2, above, is "Yes," indicate the total number of Part 2 attachments included in this submittal. *(For reference only)*	5
*	*For Site Operating Permits (SOPs), the complete application should be consulted for applicable requirements and their corresponding emission units when assessing compliance status.* *For General Operating Permits (GOPs), the application documentation, particularly Form OP-REQ1 should be consulted as well as the requirements contained in the appropriate General Permits portion of 30 TAC Chapter 122.* *Compliance should be assessed based, at a minimum, on the required monitoring, testing, record keeping, and/or reporting requirements, as appropriate, associated with the applicable requirement in question.*	

TCEQ

Texas Commission on Environmental Quality
Form OP-ACPS
Application Compliance Plan and Schedule

Date:01/14/2014	Regulated Entity No.:100228899	Permit No.: O3546
Company Name: Nuevo Midstream, LLC	Area Name: Ramsey Gas Plant	

Part 2

A. Compliance Schedule

If there are non-compliance situations ongoing at time of application, then complete a separate OP-ACPS Part 2 for each separate non-compliance situation. *(See form instructions for details.)* If there are no non-compliance situations ongoing at time of application, then this section is not required to be completed.

1. Specific Non-Compliance Situation

Unit/Group/Process ID. No(s).	SOP Index No.	Pollutant	Applicable Requirement	
			Citation	Text Description
Area-wide			§122.145(2)	Deviations from permit conditions must be reported. A report shall be submitted every 6 months no later than 30 days after the end of the reporting period.

2. Compliance Status Assessment Method and Records Location

Compliance Status Assessment Method

Citation	Text Description	Location of Records/Documentation
§122.145(2)	Submit semi-annual Deviation Report	Records at the Plant.

3. Non-compliance Situation Description

Failure to submit semi-annual Deviation Report

TCEQ

Texas Commission on Environmental Quality
Form OP-ACPS
Application Compliance Plan and Schedule

Date:01/14/2014	**Regulated Entity No.: 100228899**	**Permit No.: O3546**
Company Name: Nuevo Midstream, LLC	**Area Name: Ramsey Gas Plant**	

Part 2 (*continued*)

4. Corrective Action Plan Description			
Submit report by end of January 2014. Develop regulatory compliance schedule to prevent re-occurrence.			
5. List of Activities/Milestones to Implement the Corrective Action Plan			
1	Submit report January 31, 2014		
2	Develop regulatory compliance schedule January 31, 2014		
3			
4			
5			
6. Previously Submitted Compliance Plan(s)		**Type of Action**	**Date Submitted**
		Non-compliance submitted via Texas Audit Act	January 6,2014
7. Progress Report Submission Schedule		January 31, 2014	

TCEQ

Texas Commission on Environmental Quality
Form OP-ACPS
Application Compliance Plan and Schedule

Date:01/14/2014	**Regulated Entity No.:100228899**	**Permit No.: O3546**
Company Name: Nuevo Midstream, LLC		**Area Name: Ramsey Gas Plant**

Part 2

A. Compliance Schedule

If there are non-compliance situations ongoing at time of application, then complete a separate OP-ACPS Part 2 for each separate non-compliance situation. *(See form instructions for details.)* If there are no non-compliance situations ongoing at time of application, then this section is not required to be completed.

1. Specific Non-Compliance Situation

Unit/Group/Process ID. No(s).	SOP Index No.	Pollutant	Applicable Requirement	
			Citation	Text Description
Area-wide			§122.146	Permit holder shall certify compliance with the terms and conditions of the permit at least each 12-month period following permit issuance.

2. Compliance Status Assessment Method and Records Location

Compliance Status Assessment Method

Citation	Text Description	Location of Records/Documentation
§122.146	Submit annual compliance certification.	Records at the Plant.

3. Non-compliance Situation Description

Failure to submit annual compliance certification.

Texas Commission on Environmental Quality
Form OP-ACPS
Application Compliance Plan and Schedule

Date:01/14/2014	**Regulated Entity No.: 100228899**	**Permit No.: O3546**
Company Name: Nuevo Midstream, LLC		**Area Name: Ramsey Gas Plant**

Part 2 (*continued*)

4. Corrective Action Plan Description		
Submit report by end of January 2014. Develop regulatory compliance schedule to prevent re-occurrence.		
5. List of Activities/Milestones to Implement the Corrective Action Plan		
1	Submit report by January 31, 2014	
2	Develop regulatory compliance schedule by January31, 2014	
3		
4		
5		
6. Previously Submitted Compliance Plan(s)	**Type of Action**	**Date Submitted**
	Non-compliance submitted via Texas Audit Act	January 6,2014
7. Progress Report Submission Schedule	January 31, 2014	

Texas Commission on Environmental Quality
Form OP-ACPS
Application Compliance Plan and Schedule

Date:01/14/2014	Regulated Entity No.:100228899	Permit No.: O3546
Company Name: Nuevo Midstream, LLC		Area Name: Ramsey Gas Plant

Part 2

A. Compliance Schedule

If there are non-compliance situations ongoing at time of application, then complete a separate OP-ACPS Part 2 for each separate non-compliance situation. *(See form instructions for details.)* If there are no non-compliance situations ongoing at time of application, then this section is not required to be completed.

1. Specific Non-Compliance Situation

Unit/Group/Process ID. No(s).	SOP Index No.	Pollutant	Applicable Requirement	
			Citation	Text Description
Area-wide			§101.20	Shall comply with applicable new source performance standards promulgated by EPA pursuant to the Federal Clean Air Act §111, as amended.

2. Compliance Status Assessment Method and Records Location

Compliance Status Assessment Method

Citation	Text Description	Location of Records/Documentation
§101.20	Perform stack testing of engines in a timely manner.	Records at the Plant.

3. Non-compliance Situation Description

Completed stack testing late.

TCEQ

Texas Commission on Environmental Quality
Form OP-ACPS
Application Compliance Plan and Schedule

Date:01/14/2014	**Regulated Entity No.: 100228899**	**Permit No.: O3546**
Company Name: Nuevo Midstream, LLC	**Area Name: Ramsey Gas Plant**	

Part 2 (*continued*)

4. Corrective Action Plan Description			
Develop regulatory compliance schedule to prevent re-occurrence.			
5. List of Activities/Milestones to Implement the Corrective Action Plan			
1	Develop regulatory compliance schedule by January 31, 2014.		
2			
3			
4			
5			
6. Previously Submitted Compliance Plan(s)		**Type of Action**	**Date Submitted**
		Non-compliance submitted via Texas Audit Act	January 6,2014
7. Progress Report Submission Schedule		January 31, 2014	

Texas Commission on Environmental Quality
Form OP-ACPS
Application Compliance Plan and Schedule

Date:01/14/2014	**Regulated Entity No.:100228899**	**Permit No.: O3546**
Company Name: Nuevo Midstream, LLC		**Area Name: Ramsey Gas Plant**

Part 2

A. Compliance Schedule

If there are non-compliance situations ongoing at time of application, then complete a separate OP-ACPS Part 2 for each separate non-compliance situation. *(See form instructions for details.)* If there are no non-compliance situations ongoing at time of application, then this section is not required to be completed.

1. Specific Non-Compliance Situation

Unit/Group/Process ID. No(s).	SOP Index No.	Pollutant	Applicable Requirement	
			Citation	Text Description
Area-wide			§101.20	Shall comply with applicable new source performance standards promulgated by EPA pursuant to the Federal Clean Air Act §111, as amended.

2. Compliance Status Assessment Method and Records Location

Compliance Status Assessment Method

Citation	Text Description	Location of Records/Documentation
§101.20	Engine stack reports shall be submitted.	Records at the Plant.

3. Non-compliance Situation Description

Failure to submit the engine stack testing reports.

Date:01/14/2014	**Regulated Entity No.: 100228899**	**Permit No.: O3546**
Company Name: Nuevo Midstream, LLC	**Area Name: Ramsey Gas Plant**	

Part 2 (*continued)*

4.	**Corrective Action Plan Description**	
Submit report by end of January 2014. Develop regulatory compliance schedule to prevent re-occurrence.		
5.	**List of Activities/Milestones to Implement the Corrective Action Plan**	
1	The reports will be submitted by January 31, 2014.	
2	Develop regulatory compliance schedule by end of January 2014.	
3		
4		
5		
6. Previously Submitted Compliance Plan(s)	**Type of Action**	**Date Submitted**
	Non-compliance submitted via Texas Audit Act	January 6,2014
7. Progress Report Submission Schedule	January 31, 2014	

Texas Commission on Environmental Quality
Form OP-ACPS
Application Compliance Plan and Schedule

Date:01/14/2014	**Regulated Entity No.:100228899**	**Permit No.: O3546**
Company Name: Nuevo Midstream, LLC		**Area Name: Ramsey Gas Plant**

Part 2

A. Compliance Schedule

If there are non-compliance situations ongoing at time of application, then complete a separate OP-ACPS Part 2 for each separate non-compliance situation. *(See form instructions for details.)* If there are no non-compliance situations ongoing at time of application, then this section is not required to be completed.

1. Specific Non-Compliance Situation

Unit/Group/Process ID. No(s).	SOP Index No.	Pollutant	Applicable Requirement	
			Citation	Text Description
Area-wide			§101.201	Reportable emission events shall be reported.

2. Compliance Status Assessment Method and Records Location

Compliance Status Assessment Method

Citation	Text Description	Location of Records/Documentation
§101.201	Report reportable emission events.	Records at the Plant.

3. Non-compliance Situation Description

Reportable emission event was not reported.

Texas Commission on Environmental Quality
Form OP-ACPS
Application Compliance Plan and Schedule

Date:01/14/2014	**Regulated Entity No.: 100228899**	**Permit No.: O3546**
Company Name: Nuevo Midstream, LLC	**Area Name: Ramsey Gas Plant**	

Part 2 (*continued*)

4. Corrective Action Plan Description			
Train employees on the correct upset reporting requirements. Study options for preventing mechanical issues with the inlet and booster compressors			
5. List of Activities/Milestones to Implement the Corrective Action Plan			
1	Train employees on the correct upset reporting requirements. Training will be completed by February 28, 2014		
2	Report upset emissions by February 28, 2014.		
3	Identify options to improve the reliability of the inlet and booster compressors, which cause the excess emissions. Study completed by February 28, 2014.		
4			
5			
6. Previously Submitted Compliance Plan(s)		**Type of Action**	**Date Submitted**
		Non-compliance submitted via Texas Audit Act	January 6,2014
7. Progress Report Submission Schedule		February 28, 2014	

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: 01/15/2014	**Permit No.:**	**Regulated Entity No.:** RN100228899
Area Name: Ramsey Gas Plant		**Customer Reference No.:** CN604322891

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

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) Name**		**(A) Pound Per Hour**	**(B) TPY**
COMP-15	COMP-15	Cat G3612 LE or equivalent	CO2	3,435.736	15,048.525
			CH4	41.949	183.736
			N2O	0.005	0.023
			CO2e	4,318.271	18,914.010
COMP-16	COMP-16	Cat G3612 LE or equivalent	CO2	3,435.736	15,048.525
			CH4	41.949	183.736
			N2O	0.005	0.023
			CO2e	4,318.271	18,914.010
COMP-17	COMP-17	Cat G3612 LE or equivalent	CO2	3,435.736	15,048.525
			CH4	41.949	183.736

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY
			N2O	0.005	0.023
			CO2e	4,318.271	18,914.010
COMP-18	COMP-18	Cat G3612 LE or equivalent	CO2	3,435.736	15,048.525
			CH4	41.949	183.736
			N2O	0.005	0.023
			CO2e	4,318.271	18,914.010
COMP-19	COMP-19	Cat G3612 LE or equivalent	CO2	3,435.736	15,048.525
			CH4	41.949	183.736
			N2O	0.005	0.023
			CO2e	4,318.271	18,914.010
COMP-20	COMP-20	Cat G3612 LE or equivalent	CO2	3,435.736	15,048.525
			CH4	41.949	183.736
			N2O	0.005	0.023
			CO2e	4,318.271	18,914.010
COMP-21	COMP-21	Cat G3612 LE or equivalent	CO2	3,435.736	15,048.525

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY
			CH_4	41.949	183.736
			N_2O	0.005	0.023
			CO_2e	4,318.271	18,914.010
COMP-22	COMP-22	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	41.949	183.736
			N_2O	0.005	0.023
			CO_2e	4,318.271	18,914.010
COMP-23	COMP-23	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	41.949	183.736
			N_2O	0.005	0.023
			CO_2e	4,318.271	18,914.010
COMP-24	COMP-24	Cat G3612 LE or equivalent	CO_2	3,435.736	15,048.525
			CH_4	41.949	183.736
			N_2O	0.005	0.023
			CO_2e	4,318.271	18,914.010

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY
COMP-25	COMP-25	Cat G3612 LE or equivalent	CO2	3,435.736	15,048.525
			CH4	41.949	183.736
			N2O	0.005	0.023
			CO2e	4,318.271	18,914.010
COMP-26	COMP-26	Cat G3612 LE or equivalent	CO2	3,435.736	15,048.525
			CH4	41.949	183.736
			N2O	0.005	0.023
			CO2e	4,318.271	18,914.010
COMP-27	COMP-27	Cat G3612 LE or equivalent	CO2	3,435.736	15,048.525
			CH4	41.949	183.736
			N2O	0.005	0.023
			CO2e	4,318.271	18,914.010
COMP-28	COMP-28	Cat G3612 LE or equivalent	CO2	3,435.736	15,048.525
			CH4	41.949	183.736
			N2O	0.005	0.023

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) Name**		**(A) Pound Per Hour**	**(B) TPY**
			CO2e	4,318.271	18,914.010
COMP-29	COMP-29	Cat G3612 LE or equivalent	CO2	3,435.736	15,048.525
			CH4	41.949	183.736
			N2O	0.005	0.023
			CO2e	4,318.271	18,914.010
BD3	BD3	Engine blowdowns for	CO2	2.183	0.098
			CH4	367.824	16.552
			N2O	0.000	0.000
			CO2e	7,726.484	347.692
BD4	BD4	Engine blowdowns for	CO2	2.183	0.098
			CH4	367.824	16.552
			N2O	0.000	0.000
			CO2e	7,726.484	347.692
BD5	BD5	Engine blowdowns for	CO2	2.183	0.098
			CH4	367.824	16.552

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) Name**		**(A) Pound Per Hour**	**(B) TPY**
			N2O	0.000	0.000
			CO2e	7,726.484	347.692
H-8	H-8	36 MMBtu/hr or equivalent Regen	CO2	4,207.964	18,430.883
			CH4	0.079	0.347
			N2O	0.008	0.035
			CO2e	4,212.091	18,448.921
H-9	H-9	60 MMBtu/hr or equivalent Hot Oil	CO2	7,013.274	30,718.138
			CH4	0.132	0.578
			N2O	0.013	0.058
			CO2e	7,020.152	30,748.202
H-10	H-10	36 MMBtu/hr or equivalent Regen	CO2	4,207.964	18,430.883
			CH4	0.079	0.347
			N2O	0.008	0.035
			CO2e	4,212.091	18,448.921
H-11	H-11	60 MMBtu/hr or equivalent Hot Oil	CO2	7,013.274	30,718.138

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) Name**		**(A) Pound Per Hour**	**(B) TPY**
			CH4	0.132	0.578
			N2O	0.013	0.058
			CO2e	7,020.152	30,748.202
H-12	H-12	36 MMBtu/hr or equivalent Regen	CO2	4,207.964	18,430.883
			CH4	0.079	0.347
			N2O	0.008	0.035
			CO2e	4,212.091	18,448.921
RTO-4	RTO-4	Regenerative Thermal Oxidizer	CO2	22,991.867	96,619.845
			CH4	0.202	0.809
			N2O	0.002	0.000
			CO2e	22,996.660	96,636.836
RTO-5	RTO-5	Regenerative Thermal Oxidizer	CO2	22,991.867	96,619.845
			CH4	0.202	0.809
			N2O	0.002	0.000
			CO2e	22,996.660	96,636.836

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) Name**		**(A) Pound Per Hour**	**(B) TPY**
FUG4	FUG4	Fugitive Emissions	CO2	0.251	1.098
			CH4	2.000	8.760
			N2O	0.000	0.000
			CO2e	35.566	155.781
FUG5	FUG5	Fugitive Emissions	CO2	0.251	1.098
			CH4	2.000	8.760
			N2O	0.000	0.000
			CO2e	35.566	155.781
FUG6	FUG6	Fugitive Emissions	CO2	0.251	1.098
			CH4	2.000	8.760
			N2O	0.000	0.000
			CO2e	35.566	155.781

EPN = Emission Point Number
FIN = Facility Identification Number

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: 01/15/2014	**Permit No.:**	**Regulated Entity No.:** RN100228899
Area Name: Ramsey Gas Plant		**Customer Reference No.:** CN604322891

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

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS							
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
			5.			5. Building Height (Ft.)	6. Height Above Ground (Ft.)	7. Stack Exit Data			8. Fugitives		
(A) EPN	(B) FIN	(C) NAME	Zone	East (Meters)	North (Meters)			(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees
COMP-15	COMP-15	Cat G3612LE	13R	594,444	3,532,498	None	22.2	1.92	117.37	838			
COMP-16	COMP-16	Cat G3612LE	13R	594,444	3,532,498	None	22.2	1.92	117.37	838			
COMP-17	COMP-17	Cat G3612LE	13R	594,444	3,532,498	None	22.2	1.92	117.37	838			
COMP-18	COMP-18	Cat G3612LE	13R	594,444	3,532,498	None	22.2	1.92	117.37	838			
COMP-19	COMP-19	Cat G3612LE	13R	594,444	3,532,498	None	22.2	1.92	117.37	838			
COMP-20	COMP-20	Cat G3612LE	13R	594,444	3,532,498	None	22.2	1.92	117.37	838			
COMP-21	COMP-21	Cat G3612LE	13R	594,444	3,532,498	None	22.2	1.92	117.37	838			
COMP-22	COMP-22	Cat G3612LE	13R	594,444	3,532,498	None	22.2	1.92	117.37	838			
COMP-23	COMP-23	Cat G3612LE	13R	594,444	3,532,498	None	22.2	1.92	117.37	838			

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS							
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
			5.			5. Building Height (Ft.)	6. Height Above Ground (Ft.)	7. Stack Exit Data			8. Fugitives		
(A) EPN	(B) FIN	(C) NAME	Zone	East (Meters)	North (Meters)			(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees
COMP-24	COMP-24	Cat G3612LE	13R	594,444	3,532,498	None	22.2	1.92	117.37	838			
COMP-25	COMP-25	Cat G3612LE	13R	594,444	3,532,498	None	22.2	1.92	117.37	838			
COMP-26	COMP-26	Cat G3612LE	13R	594,444	3,532,498	None	22.2	1.92	117.37	838			
COMP-27	COMP-27	Cat G3612LE	13R	594,444	3,532,498	None	22.2	1.92	117.37	838			
COMP-28	COMP-28	Cat G3612LE	13R	594,444	3,532,498	None	22.2	1.92	117.37	838			
COMP-29	COMP-29	Cat G3612LE	13R	594,444	3,532,498	None	22.2	1.92	117.37	838			
H-8	H-8	36 MMBtu/hr Heater	13R	594,444	3,532,498	None	25	1.5	9.64	787			
H-9	H-9	60 MMBtu/hr Heater	13R	594,444	3,532,498	None	??	2	10.28	787			
H-10	H-10	36 MMBtu/hr Heater	13R	594,444	3,532,498	None	25	1.5	9.64	787			
H-11	H-11	60 MMBtu/hr Heater	13R	594,444	3,532,498	None	??	2	10.28	787			
H-12	H-12	36 MMBtu/hr Heater	13R	594,444	3,532,498	None	25	1.5	9.64	787			
RTO-4	RTO-4	Regenerative Thermal Oxidizer	13R	594,444	3,532,498	None	40	4.5	4.76	150			

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS							
1. Emission Point			**4. UTM Coordinates of Emission Point**			**Source**							
			5.			**5. Building Height (Ft.)**	**6. Height Above Ground (Ft.)**	**7. Stack Exit Data**			**8. Fugitives**		
(A) EPN	**(B) FIN**	**(C) NAME**	**Zone**	**East (Meters)**	**North (Meters)**			**(A) Diameter (Ft.)**	**(B) Velocity (FPS)**	**(C) Temperature (°F)**	**(A) Length (Ft.)**	**(B) Width (Ft.)**	**(C) Axis Degrees**
RTO-5	RTO-5	Regenerative Thermal Oxidizer	13R	594,444	3,532,498	None	40	4.5	4.76	150			
FUG4	FUG4	Fugitive Emissions	13R	594,444	3,532,498						800	767	
FUG5	FUG5	Fugitive Emissions	13R	594,444	3,532,498						800	767	
FUG6	FUG6	Fugitive Emissions	13R	594,444	3,532,498						800	767	

EPN = Emission Point Number
FIN = Facility Identification Number

RAMSEY IV GAS PLANT
NUEVO MIDSTREAM, LLC
1/14/2014

Engine Input Maximum Operating Parameters (individual emissions)

Description						
Item	EPN	C-15	C-16	C-17	C-18	C-19
	Make	CAT	CAT	CAT	CAT	CAT
	Model	3612 LE	3612 LE	3612 LE	3612 LE	3612 LE
Engine RPM=		1,000	1,000	1,000	1,000	1,000
Fuel Consumption Factor (Btu/bhp-hr)=		6,629	6,629	6,629	6,629	6,629
Engine BHp Rating=		3,550	3,550	3,550	3,550	3,550
Fuel Heating Value (Btu/SCF)=		1,077	1,077	1,077	1,077	1,077
Exhaust Gas Temperature (°F)=		838	838	838	838	838
Exhaust Gas Flow (lb/hr)=		34,250	34,250	34,250	34,250	34,250
Fuel Gas Molecular Weight (lb/lb-mole)=		17.895	17.895	17.895	17.895	17.895
For Exhaust Gas, K=		720.9	720.9	720.9	720.9	720.9
Engine Fuel Consumption (SCF/hr)=		21,844.379	21,844.379	21,844.379	21,844.379	21,844.379
Engine Fuel Consumption (lb/hr)=		1,031.428	1,031.428	1,031.428	1,031.428	1,031.428
Compression Limit (Hp-hr/yr)=		None	None	None	None	None
Engine Exhaust Gas Flow (CF/min)=		24,090	24,090	24,090	24,090	24,090
Engine Exhaust Gas Flow (CF/hr)=		1,445,400	1,445,400	1,445,400	1,445,400	1,445,400
Stack Exit Velocity (feet/second)		88.75	88.75	88.75	88.75	88.75
Engine % Utilization		100%	100%	100%	100%	100%
Stack Diameter (ft)=		1.667	1.667	1.667	1.667	1.667
Stack Height (ft)		22.2	22.2	22.2	22.2	22.2
Emission Limited Per Engine? (yes/no)		no	no	no	no	no
Atmospheric Pressure (psia)		14.7	14.7	14.7	14.7	14.7
Emission Factors: (grams/Hp-hr)						
	VOC	0.091	0.091	0.091	0.091	0.091
	NOx	0.500	0.500	0.500	0.500	0.500
	CO	0.083	0.083	0.083	0.083	0.083
	Formaldehyde	0.0200	0.0200	0.0200	0.0200	0.0200
Emission Factors: (lbs/MMBtu)						
	PM primary	0.01	0.01	0.01	0.01	0.01
	PM_{10}	0.0001	0.0001	0.0001	0.0001	0.0001
	$PM_{2.5}$	0.0001	0.0001	0.0001	0.0001	0.0001
	$PM_{Condensable}$	0.01	0.01	0.01	0.01	0.01
	SO_2	0.001	0.001	0.001	0.001	0.001

ESTIMATED CO2e POTENTIAL TO EMIT (PTE) EMISSIONS USING VENDOR DATA AND 40 CFR 98 EMISSION FACTORS

Facility: Ramsey Gas Plant

Unit Description		Rating			Heat Input	Emission Factors		
Gas-Fired Compressor Engines		**hp**	**Fuel Factor**	**Hours of Operation**	**Maximum (MMBtu /yr)**	**CO_2**	**CH_4**	**N_2O**
			Btu/bhp-hr			g/bhp-hr[1]	g/bhp-hr[1]	kg/MMBtu[2]
C-15	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-16	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-17	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-18	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-19	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04

EMISSIONS

	CO_2	**CH_4**	**N_2O**	**CO_2e**	**CO_2**	**CH_4**	**N_2O**	**CO_2e**	
	lbs/hr	lbs/hr	lbs/hr	lbs/hr	TPY	TPY	TPY	TPY	
C-15	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-16	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-17	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-18	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-19	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
			TOTAL	**22,430**	lbs/hr		**TOTAL**	**98,245**	**TPY**

1 Vendor Data
2 40 CFR 98 Table C-2 Emission Factor

RESIDUE (FUEL) GAS ANALYSIS
1/14/2014

RAMSEY IV GAS PLANT
Analysis Provided by Nuevo Midstream

FUEL HEAT CONTENT, BTU/SCF 1,077

COMPOUND	INLET GAS MOL%	MOL. WT.	CALC. MOL. WT.	WT %
BENZENE	0.000	78.110	0.0000	0.000
BUTANE+	0.000	58.120	0.0000	0.000
CO2	0.188	44.010	0.0827	0.462
DECANE+	0.000	142.290	0.0000	0.000
ETHANE	10.637	30.070	3.1985	17.874
ETHYLBENZENE	0.000	106.160	0.0000	0.000
HEPTANES+	0.000	100.210	0.0000	0.000
HEXANES+	0.000	86.178	0.0000	0.000
METHANE	86.911	16.040	13.9405	77.901
NITROGEN	2.020	28.013	0.5659	3.162
NONANE+	0.000	128.200	0.0000	0.000
OCTANE+	0.000	114.230	0.0000	0.000
PENTANE+	0.000	72.151	0.0000	0.000
PROPANE	0.244	44.100	0.1076	0.601
TOLUENE	0.000	92.130	0.0000	0.000
XYLENES	0.000	106.160	0.0000	0.000
REAL BTU/CU.FT.				
At 14.65 DRY		1071.400		
At 14.65 WET		1052.700		
At 14.696 DRY		1074.800		
At 14.696 WET		1056.400		
At 14.73 DRY		1077.300		
At 14.73 Wet		1058.700		
	100		17.8953	100.000

Molecular Weight	
RESIDUE GAS M. WT.	17.895

RAMSEY V GAS PLANT
NUEVO MIDSTREAM, LLC
1/14/2014

Engine Input Maximum Operating Parameters (individual emissions)

Description						
Item	EPN	C-20	C-21	C-22	C-23	C-24
	Make	CAT	CAT	CAT	CAT	CAT
	Model	3612 LE	3612 LE	3612 LE	3612 LE	3612 LE
Engine RPM=		1,000	1,000	1,000	1,000	1,000
Fuel Consumption Factor (Btu/bhp-hr)=		6,629	6,629	6,629	6,629	6,629
Engine BHp Rating=		3,550	3,550	3,550	3,550	3,550
Fuel Heating Value (Btu/SCF)=		1,077	1,077	1,077	1,077	1,077
Exhaust Gas Temperature (°F)=		838	838	838	838	838
Exhaust Gas Flow (lb/hr)=		34,250	34,250	34,250	34,250	34,250
Fuel Gas Molecular Weight (lb/lb-mole)=		17.895	17.895	17.895	17.895	17.895
For Exhaust Gas, K=		720.9	720.9	720.9	720.9	720.9
Engine Fuel Consumption (SCF/hr)=		21,844.379	21,844.379	21,844.379	21,844.379	21,844.379
Engine Fuel Consumption (lb/hr)=		1,031.428	1,031.428	1,031.428	1,031.428	1,031.428
Compression Limit (Hp-hr/yr)=		None	None	None	None	None
Engine Exhaust Gas Flow (CF/min)=		24,090	24,090	24,090	24,090	24,090
Engine Exhaust Gas Flow (CF/hr)=		1,445,400	1,445,400	1,445,400	1,445,400	1,445,400
Stack Exit Velocity (feet/second)		88.75	88.75	88.75	88.75	88.75
Engine % Utilization		100%	100%	100%	100%	100%
Stack Diameter (ft)=		1.667	1.667	1.667	1.667	1.667
Stack Height (ft)		22.2	22.2	22.2	22.2	22.2
Emission Limited Per Engine? (yes/no)		no	no	no	no	no
Atmospheric Pressure (psia)		14.7	14.7	14.7	14.7	14.7
Emission Factors: (grams/Hp-hr)						
	VOC	0.091	0.091	0.091	0.091	0.091
	NOx	0.500	0.500	0.500	0.500	0.500
	CO	0.083	0.083	0.083	0.083	0.083
	Formaldehyde	0.020	0.020	0.020	0.020	0.020
Emission Factors: (lbs/MMBtu)						
	PM primary	0.01	0.01	0.01	0.01	0.01
	PM_{10}	0.0001	0.0001	0.0001	0.0001	0.0001
	$PM_{2.5}$	0.0001	0.0001	0.0001	0.0001	0.0001
	$PM_{Condensable}$	0.01	0.01	0.01	0.01	0.01
	SO_2	0.001	0.001	0.001	0.001	0.001

ESTIMATED CO2e POTENTIAL TO EMIT (PTE) EMISSIONS USING VENDOR DATA AND 40 CFR 98 EMISSION FACTORS

Facility: Ramsey Gas Plant

Unit Description		Rating			Heat Input	Emission Factors		
Gas-Fired Compressor Engines		**hp**	**Fuel Factor**	**Hours of Operation**	**Maximum (MMBtu /yr)**	**CO_2**	**CH_4**	**N_2O**
			Btu/bhp-hr			g/bhp-hr[1]	g/bhp-hr[1]	kg/MMBtu[2]
C-20	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-21	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-22	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-23	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-24	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04

EMISSIONS

	CO_2	**CH_4**	**N_2O**	**CO_2e**	**CO_2**	**CH_4**	**N_2O**	**CO_2e**	
	lbs/hr	lbs/hr	lbs/hr	lbs/hr	TPY	TPY	TPY	TPY	
C-20	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-21	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-22	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-23	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-24	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
			TOTAL	**22,430**	lbs/hr		**TOTAL**	**98,245**	**TPY**

1 Vendor Data
2 40 CFR 98 Table C-2 Emission Factor

RESIDUE (FUEL) GAS ANALYSIS
1/14/2014

RAMSEY IV GAS PLANT
Analysis Provided by Nuevo Midstream

FUEL HEAT CONTENT, BTU/SCF 1,077

COMPOUND	INLET GAS MOL%	MOL. WT.	CALC. MOL. WT.	WT %
BENZENE	0.000	78.110	0.0000	0.000
BUTANE+	0.000	58.120	0.0000	0.000
CO2	0.188	44.010	0.0827	0.462
DECANE+	0.000	142.290	0.0000	0.000
ETHANE	10.637	30.070	3.1985	17.874
ETHYLBENZENE	0.000	106.160	0.0000	0.000
HEPTANES+	0.000	100.210	0.0000	0.000
HEXANES+	0.000	86.178	0.0000	0.000
METHANE	86.911	16.040	13.9405	77.901
NITROGEN	2.020	28.013	0.5659	3.162
NONANE+	0.000	128.200	0.0000	0.000
OCTANE+	0.000	114.230	0.0000	0.000
PENTANE+	0.000	72.151	0.0000	0.000
PROPANE	0.244	44.100	0.1076	0.601
TOLUENE	0.000	92.130	0.0000	0.000
XYLENES	0.000	106.160	0.0000	0.000
REAL BTU/CU.FT.				
At 14.65 DRY		1071.400		
At 14.65 WET		1052.700		
At 14.696 DRY		1074.800		
At 14.696 WET		1056.400		
At 14.73 DRY		1077.300		
At 14.73 Wet		1058.700		
	100		17.8953	100.000

Molecular Weight	
RESIDUE GAS M. WT.	17.895

RAMSEY VI GAS PLANT
NUEVO MIDSTREAM, LLC
1/14/2014

Engine Input Maximum Operating Parameters (individual emissions)

Description						
Item	EPN	C-25	C-26	C-27	C-28	C-29
	Make	CAT	CAT	CAT	CAT	CAT
	Model	3612 LE	3612 LE	3612 LE	3612 LE	3612 LE
Engine RPM=		1,000	1,000	1,000	1,000	1,000
Fuel Consumption Factor (Btu/bhp-hr)=		6,629	6,629	6,629	6,629	6,629
Engine BHp Rating=		3,550	3,550	3,550	3,550	3,550
Fuel Heating Value (Btu/SCF)=		1,077	1,077	1,077	1,077	1,077
Exhaust Gas Temperature (°F)=		838	838	838	838	838
Exhaust Gas Flow (lb/hr)=		34,250	34,250	34,250	34,250	34,250
Fuel Gas Molecular Weight (lb/lb-mole)=		17.895	17.895	17.895	17.895	17.895
For Exhaust Gas, K=		720.9	720.9	720.9	720.9	720.9
Engine Fuel Consumption (SCF/hr)=		21,844.379	21,844.379	21,844.379	21,844.379	21,844.379
Engine Fuel Consumption (lb/hr)=		1,031.428	1,031.428	1,031.428	1,031.428	1,031.428
Compression Limit (Hp-hr/yr)=		None	None	None	None	None
Engine Exhaust Gas Flow (CF/min)=		24,090	24,090	24,090	24,090	24,090
Engine Exhaust Gas Flow (CF/hr)=		1,445,400	1,445,400	1,445,400	1,445,400	1,445,400
Stack Exit Velocity (feet/second)		88.75	88.75	88.75	88.75	88.75
Engine % Utilization		100%	100%	100%	100%	100%
Stack Diameter (ft)=		1.667	1.667	1.667	1.667	1.667
Stack Height (ft)		22.2	22.2	22.2	22.2	22.2
Emission Limited Per Engine? (yes/no)		no	no	no	no	no
Atmospheric Pressure (psia)		14.7	14.7	14.7	14.7	14.7
Emission Factors: (grams/Hp-hr)						
	VOC	0.091	0.091	0.091	0.091	0.091
	NOx	0.500	0.500	0.500	0.500	0.500
	CO	0.083	0.083	0.083	0.083	0.083
	Formaldehyde	0.020	0.020	0.020	0.020	0.020
Emission Factors: (lbs/MMBtu)						
	PM primary	0.01	0.01	0.01	0.01	0.01
	PM_{10}	0.0001	0.0001	0.0001	0.0001	0.0001
	$PM_{2.5}$	0.0001	0.0001	0.0001	0.0001	0.0001
	$PM_{Condensable}$	0.01	0.01	0.01	0.01	0.01
	SO_2	0.001	0.001	0.001	0.001	0.001

ESTIMATED CO_2e POTENTIAL TO EMIT (PTE) EMISSIONS USING MANUFACTURER DATA AND 40 CFR 98 EMISSION FACTORS

Facility: Ramsey Gas Plant

Unit Description		Rating		Heat Input		Emission Factors		
Gas-Fired Compressor Engines		hp	Fuel Factor	Hours of Operation	Maximum (MMBtu /yr)	CO_2	CH_4	N_2O
			Btu/bhp-hr			g/bhp-hr[1]	g/bhp-hr[1]	kg/MMBtu[2]
C-25	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-26	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-27	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-28	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04
C-29	3612 LE	3,550	6,629	8760	206,149	439	5.36	1.00E-04

EMISSIONS

	CO_2	CH_4	N_2O	CO_2e	CO_2	CH_4	N_2O	CO_2e	
	lbs/hr	lbs/hr	lbs/hr	lbs/hr	TPY	TPY	TPY	TPY	
C-25	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-26	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-27	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-28	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
C-29	3,436	41.95	0.005	**4,486**	15048.5	183.74	0.023	**19,649**	
			TOTAL	**22,430**	lbs/hr		**TOTAL**	**98,245**	**TPY**

1 Vendor Data
2 40 CFR 98 Table C-2 Emission Factor

RESIDUE (FUEL) GAS ANALYSIS
1/14/2014

RAMSEY IV GAS PLANT
Analysis Provided by Nuevo Midstream

FUEL HEAT CONTENT, BTU/SCF 1,077

COMPOUND	INLET GAS MOL%	MOL. WT.	CALC. MOL. WT.	WT %
BENZENE	0.000	78.110	0.0000	0.000
BUTANE+	0.000	58.120	0.0000	0.000
CO2	0.188	44.010	0.0827	0.462
DECANE+	0.000	142.290	0.0000	0.000
ETHANE	10.637	30.070	3.1985	17.874
ETHYLBENZENE	0.000	106.160	0.0000	0.000
HEPTANES+	0.000	100.210	0.0000	0.000
HEXANES+	0.000	86.178	0.0000	0.000
METHANE	86.911	16.040	13.9405	77.901
NITROGEN	2.020	28.013	0.5659	3.162
NONANE+	0.000	128.200	0.0000	0.000
OCTANE+	0.000	114.230	0.0000	0.000
PENTANE+	0.000	72.151	0.0000	0.000
PROPANE	0.244	44.100	0.1076	0.601
TOLUENE	0.000	92.130	0.0000	0.000
XYLENES	0.000	106.160	0.0000	0.000
REAL BTU/CU.FT.				
At 14.65 DRY		1071.400		
At 14.65 WET		1052.700		
At 14.696 DRY		1074.800		
At 14.696 WET		1056.400		
At 14.73 DRY		1077.300		
At 14.73 Wet		1058.700		
	100		17.8953	100.000

Molecular Weight	
RESIDUE GAS M. WT.	17.895

Engine Blowdowns
Engine MSS Calculations

Nuevo Midstream LLC

1/14/2014

	EPN	ENG-MSS
Number of engines		15
Average number of events/engine/month		4
Total number of events/year		720
Estimated duration of blowdown, hours		0.25
Flowrate/event, scf		2,000
Annual event hours		180
Gas Stream Heat Value, Btu/scf		1,077
Hourly flowrate[1], scf/hr		30,000
Annual Flowrate[2], MMSCF/yr		1.44

Notes:

[1] The maximum blowdown would occur when there is a total plant shutdown where all the engines blowdown at the same time.

[2] The annual flowrate is the volume per event times the number of events per year.

Uncontrolled Emissions

COMPOUND	VENT GAS MOL%	MOL. WT.	CALC. MOL. WT.	EMISSIONS MOLES/HR	EMISSIONS LBS/HR	EMISSIONS TPY
BENZENE	0.00%	78.110	0.0000	0.000	0.00	0.00
BUTANE	0.00%	58.120	0.0000	0.000	0.00	0.00
CO_2	0.19%	44.010	0.0827	0.149	6.55	0.59
ETHANE	10.64%	30.070	3.1985	8.420	253.18	22.79
ETHYLBENZENE	0.00%	106.160	0.0000	0.000	0.00	0.00
HEXANES+	0.00%	86.178	0.0000	0.000	0.00	0.00
METHANE	86.91%	16.040	13.9405	68.795	1103.47	99.31
N2	2.02%	28.013	0.5659	1.599	44.79	4.03
PENTANE	0.00%	72.151	0.0000	0.000	0.00	0.00
PROPANE	0.24%	44.100	0.1076	0.193	8.52	0.77
TOLUENE	0.00%	92.130	0.0000	0.000	0.00	0.00
XYLENE	0.00%	106.160	0.0000	0.000	0.00	0.00
	100%		17.90	79.16	1416.51	127.49

		Per Plant			Per Plant
VOC (TPY)	0.77	0.256	HAPS (TPY)	0.00	0.000
VOC (LBS/HR)	8.52	2.839	HAPs (LBS/HR)	0.00	0.000
VOC (LBS/HR) annualized	0.18	0.058	HAPs (LBS/HR) annualized	0.00	0.000

GHG Emissions — Per Plant

	lbs/Hr	TPY	lbs/Hr	TPY
CO_2	6.55	0.59	2.18	0.20
Methane (CH_4)	1,103.47	99.31	367.82	33.10
N_2O	0.00	0.00	0.00	0.00
Total CO2e	27,593.34	2,483.40	9,197.78	827.80

HEATER/REBOILER EMISSIONS

RAMSEY GAS PLANT EXPANSION
Nuevo Midstream, LLC
1/15/2014

HEATERS/REBOILERS

DESIGN RATING

ITEMS / EPN	H-8 Regen Gas Heater	H-9 Hot Oil Heater	H-10 Regen Gas Heater	H-11 Hot Oil Heater	H-12 Regen Gas Heater
UTILIZATION PERCENTAGE	100%	100%	100%	100%	100%
HEAT INPUT RATING (MMBTU/HR)	36	60	36	60	36
THERMAL EFFICIENCY	86%	81%	86%	81%	86%
HEAT INPUT RATING ADJUSTED FOR EFFICIENCY?	YES	YES	YES	YES	YES
FUEL HEAT CONTENT (BTU/SCF)	1077	1077	1077	1077	1077
FUEL CONSUMPTION (MMSCF/YR)	292.8	488.0	292.8	488.0	292.8
HEAT INPUT (MMBTU/YR)	270,264	423,634	270,264	423,634	270,264
EXHAUST TEMPERATURE, T (F)=	787	787	787	787	787
PRESSURE, P (PSIA) =	14.7	14.7	14.7	14.7	14.7
THE RATIO OF O2 / CO2 =	1.925	1.925	1.925	1.925	1.925
THE RATIO OF H2O / CO2 =	1.85	1.85	1.85	1.85	1.85
STACK DIAMETER, (FT) =	1.5	2	1.5	2	1.5

AP-42 EMISSION FACTORS (UNCONTROLLED) EXCEPT FOR NO_X (LOW NO_X BURNER) -Tables 1.4-1 & 1.4-2:

	LBS/MMSCF
CO	84
NO_X	50
TOC	11
SO_2	0.6
PM (Total)	7.6
VOC	5.5
Lead	0.0005

HOURS OF OPERATION EPN:

MONTH	AVAILABLE HRS/MONTH	H-8 (HRS)	H-9 (HRS)	H-10 (HRS)	H-11 (HRS)	H-12 (HRS)
JAN	744	744	744	744	744	744
FEB	672	672	672	672	672	672
MAR	744	744	744	744	744	744
APRL	720	720	720	720	720	720
MAY	744	744	744	744	744	744
JUNE	720	720	720	720	720	720
JULY	744	744	744	744	744	744
AUG	744	744	744	744	744	744
SEPT	720	720	720	720	720	720
OCT	744	744	744	744	744	744
NOV	720	720	720	720	720	720
DEC	744	744	744	744	744	744
TOTAL	8,760.00	8,760.00	8,760.00	8,760.00	8,760.00	8,760.00

AP-42 EMISSIONS -- LBS/HR

COMPOUND (EPN:)	H-8	H-9	H-10	H-11	H-12
CO	2.808	4.680	2.808	4.680	2.808
NO_X	1.671	2.786	1.671	2.786	1.671
TOC	0.368	0.613	0.368	0.613	0.368

VOC	0.184	0.306	0.184	0.306	0.184
SO_2	0.020	0.033	0.020	0.033	0.020
PM (Total)	0.254	0.423	0.254	0.423	0.254

AP-42 EMISSIONS -- TONS/YR

COMPOUND	H-8	H-9	H-10	H-11	H-12
CO	12.298	20.497	12.298	20.497	12.298
NO_X	7.320	12.201	7.320	12.201	7.320
TOC	1.610	2.684	1.610	2.684	1.610
VOC	0.805	1.342	0.805	1.342	0.805
SO_2	0.088	0.146	0.088	0.146	0.088
PM (Total)	1.113	1.854	1.113	1.854	1.113

CALCULATE EXHAUST STACK VELOCITY

	H-9	H-10
VOLUME (ACF/HR) =	418,973.1	251,470.4
VOLUME (ACF/S) =	116.4	69.9
STACK DIAMETER (FT) =	2	1.5
STACK CROSS-SECTIONAL AREA=	12.57	7.07
EXHAUST VELOCITY (f/s) =	9.26	9.88

AS AN EXAMPLE:
TO CALCULATE ESTIMATED CO2 EMISSIONS AND % VOLUMES.
THE FOLLOWING CONDITIONS APPLY FOR CALCULATION OF EXHAUST GAS VOLUMES:
V(FT3/HR) = mRT/MP

EXHAUST TEMPERATURE, T (F) =	787
PRESSURE, P (PSIA) =	14.7
MASS FLOW RATE, m (LBS/HR) =	12,490
MOL. WT. , m (LBS/LB-MOL) =	27.13
GAS CONSTANT, R =	10.73

THE STOCHIOMETRIC EQN. DEPICTS THE PRIMARY COMBUSTION REACTION:
40 CH 3.7 + 77 O2 = 40 CO2 + 74 H2O

THE RATIO OF O2 / CO2 =	77/40 =	1.925
THE RATIO OF H2O / CO2 =	74/40 =	1.85

EPN: **H-9**

COMPOUND	FUEL GAS %MOLE	MOL. WT.	FUEL GAS INPUT MOL/YR	CO2 MOL/YR	EMISSIONS MOL/YR	EMISSIONS LBS/HR	FLOW RATE FT3/HR	ESTIM. VOL. %	FLWRATE TPY
BENZENE	0	78.1	0.00	0.00	0.0000	0.00	0.00	0.00	0.00
BUTANE	0	58.12	0.00	0.00	0.0000	0.00	0.00	0.00	0.00
CO	0	28			1464.0669	4.68	152.13	0.04	20.50
CO2	0.188	44.01	2,420.80	2,420.80	1,404,899	7,058.17	145,978.81	34.84	30,914.80
CYCLOHEXANE	0	84.16	0.00	0.00	0.0000	0.00	0.00	0.00	0.00
ETHANE	10.637	30.07	136,968.15	273,936.31	136.9682	0.47	14.23	0.00	2.06
ETHYLBENZENE	0	106.16	0.00	0.00	0.0000	0.00	0.00	0.00	0.00
FORMALDEHYDE	0	30	0.00	0.00		0.00	0.13	0.00	0.02
H2S		34.076			0.0000	0.03	0.89	0.00	0.15
HEXANES	0	86.17	0.00	0.00	0.0000	0.00	0.00	0.00	0.00

METHANE	86.911	16.04	1,119,116.22	1,119,116.22	72.2412	0.13	7.51	0.00	0.58
METHANOL		32.04	0.00	0.00	0.0000	0.00	0.00	0.00	0.00
N2	2.020	28.013	26,010.69		26,011	83.18	2,702.69	0.65	364.32
NOX		46.01	0.00			2.79	55.11	0.01	12.20
PENTANE	0	72.15	0.00	0.00	0.0000	0.00	0.00	0.00	0.00
PM10			0.00	0.00	0.0000	0.42		0.00	1.85
PROPANE	0.244	44.09	3,141.88	9,425.65	3.1419	0.02	0.33	0.00	0.07
SO2		64.06	0.00		0.2090	0.03	0.47	0.00	0.15
TEG		150.18	0.00	0.00	0.0000	0.00	0.00	0.00	0.00
TOLUENE	0	92.13	0.00	0.00	0.0000	0.00	0.00	0.00	0.00
TSP			0.00			0.00		0.00	0.00
VOC-U	0	97.5	0.00			0.00	0.00	0.00	0.00
WATER VAPOR		18	0.00		2,599,063	5,340.54	270,060.81	64.46	23,391.57
XYLENE	0	106.16	0.00	0.00	0.0000	0.00	0.00	0.00	0.00
	100.00		1,287,658	1,404,899	4,031,649	12,490.47	418,973.11	100.00	54,708.26

EPN: **H-10**

COMPOUND	FUEL GAS %MOLE	MOL. WT.	FUEL GAS INPUT MOL/YR	CO2 MOL/YR	EMISSIONS MOL/YR	EMISSIONS LBS/HR	FLOW RATE FT3/HR	ESTIM. VOL. %	FLWRATE TPY
BENZENE	0	78.1	0.0000	0.00	0.0000	0.00	0.0014	0.0000	0.0000
BUTANE	0	58.12	0.0000	0.00	0.0000	0.00	0.0000	0.0000	0.0000
CO	0	28			1464.0669	4.68	152.1268	0.0605	0.0000
CO2	0.188	44.01	1452.4779	1,452.48	842,939	4,234.90	87587.2885	34.8301	0.0000
CYCLOHEXANE	0	84.16	0.0000	0.00	0.0000	0.00	0.0000	0.0000	0.0000
ETHANE	10.637	30.07	82,181	164,361.78	82.1809	0.28	8.5392	0.0034	0.0000
ETHYLBENZENE	0	106.16	0.0000	0.00	0.0000	0.00	0.0000	0.0000	0.0000
FORMALDEHYDE	0	30	0.0000	0.00		0.00	0.1268	0.0001	0.0000
H2S		34.076			0.0000	0.03	0.8929	0.0004	0.0000
HEXANES	0	86.17	0.0000	0.00	0.0000	0.00	0.0000	0.0000	0.0000
METHANE	86.911	16.04	671,470	671,469.73	0.5761	0.13	7.5064	0.0030	0.0000
METHANOL		32.04	0.0000	0.00	0.0000	0.00	0.0000	0.0000	0.0000
N2	2.020	28.013	15,606		15,606	49.91	1621.6152	0.6449	0.0000
NOX		46.01	0.0000			2.79	55.1064	0.0219	0.0000
PENTANE	0	72.15	0.0000	0.00	0.0000	0.00	0.0000	0.0000	0.0000
PM10			0.0000	0.00	0.0000	0.42		0.0000	0.0000
PROPANE	0.244	44.09	1885.1309	5,655.39	1.8851	0.01	0.1959	0.0001	0.0000
SO2		64.06	0.0000		0.0000	0.03	0.4750	0.0002	0.0000
TEG		150.18	0.0000	0.00	0.0000	0.00	0.0000	0.0000	0.0000
TOLUENE	0	92.13	0.0000	0.00	0.0000	0.00	0.0000	0.0000	0.0000
TSP			0.0000			0.00		0.0000	0.0000
VOC-U	0	97.5	0.0000			0.00	0.0000	0.0000	0.0000
WATER VAPOR		18	0.0000		1,559,438	3,204.32	162036.4837	64.4356	0.0000
XYLENE	0	106.16	0.0000	0.00	0.0000	0.00	0.0000	0.0000	0.0000
	100.00		772,595	842,939	2,419,532	7,497.52	251,470	100	0

AP-42 Natural Gas Combustion HAPs

	Total =	1.89E+00
		lbs/MMSCF
91-57-6	2-Methylnaphthaleneb, c	2.40E-05
56-49-5	3-Methylchloranthreneb, c	1.80E-06
	7,12-Dimethylbenz(a)anthra	1.60E-05
83-32-9	Acenaphtheneb,c	1.80E-06
203-96-8	Acenaphthyleneb,c	1.80E-06
120-12-7	Anthraceneb,c	2.40E-06

7440-38-2	Arsenicb	2.00E-04
56-55-3	Benz(a)anthraceneb,c	1.80E-06
71-43-2	Benzeneb	2.10E-03
50-32-8	enzo(a)pyreneb,c	1.20E-06
205-99-2	Benzo(b)fluorantheneb,c	1.80E-06
191-24-2	Benzo(g,h,i)peryleneb,c	1.20E-06
205-82-3	Benzo(k)fluorantheneb,c	1.80E-06
7440-41-7	Berylliumb	1.20E-05
7440-43-9	Cadmiumb	1.10E-03
7440-47-3	Chromiumb	1.40E-03
218-01-9	Chryseneb,c	1.80E-06
7440-48-4	Cobaltb	8.40E-05
53-70-3	Dibenzo(a,h)anthraceneb,c	1.20E-06
25321-22-6	Dichlorobenzeneb	1.20E-03
206-44-0	Fluorantheneb,c	3.00E-06
86-73-7	Fluoreneb,c	2.80E-06
50-00-0	Formaldehydeb	7.50E-02
110-54-3	Hexaneb	1.80E+00
193-39-5	Indeno(1,2,3-cd)pyreneb,c	1.80E-06
7439-96-5	Manganeseb	3.80E-04
7439-97-6	Mercuryb	2.60E-04
91-20-3	Naphthaleneb	6.10E-04
7440-02-0	Nickelb	2.10E-03
85-01-8	Phenanathreneb,c	1.70E-05
129-00-0	Pyreneb, c	5.00E-06
7782-49-2	Seleniumb	2.40E-05
108-88-3	Tolueneb	3.40E-03

ESTIMATED CO_2e POTENTIAL TO EMIT (PTE) EMISSIONS USING 40 CFR 98 EMISSION FACTORS

Facility: Ramsey Gas Plant

Unit Description

	Heat Input Rating	Hours of Operation	Heat Input Maximum (MMBtu /yr)	Emission Factors CO_2	CH_4	N_2O
	MMBtu /hr			kg/MMBtu[1]	kg/MMBtu[2]	kg/MMBtu[2]
H-8	36	8,760	315,360	53.02	1.00E-03	1.00E-04
H-9	60	8,760	525,600	53.02	1.00E-03	1.00E-04
H-10	36	8,760	315,360	53.02	1.00E-03	1.00E-04
H-11	60	8,760	525,600	53.02	1.00E-03	1.00E-04
H-12	36	8,760	315,360	53.02	1.00E-03	1.00E-04

EMISSIONS

	CO_2	CH_4	N_2O	CO_2e	CO_2	CH_4	N_2O	CO_2e	
	lbs/hr	lbs/hr	lbs/hr	lbs/hr	TPY	TPY	TPY	TPY	
H-8	4,208	0.08	0.008	**4,212**	18,431	0.35	0.035	**18,449**	
H-9	7,013	0.13	0.013	**7,020**	30,718	0.58	0.058	**30,748**	
H-10	4,208	0.08	0.008	**4,212**	18,431	0.35	0.035	**18,449**	
H-11	7,013	0.13	0.013	**7,020**	30,718	0.58	0.058	**30,748**	
H-12	4,208	0.08	0.008	**4,212**	18,431	0.35	0.035	**18,449**	
			TOTAL	**26,677**	**lbs/hr**		**TOTAL**	**116,843**	**TPY**

1 40 CFR 98 Table C-1 Emission Factor
2 40 CFR 98 Table C-2 Emission Factor

PLANT FUGITIVE EMISSIONS

RAMSEY IV, V and VI GAS PLANT 1/15/2014

EPN:	FUGITIVES	LENGTH	WDTH	HT
ENTER SOURCE DIMENSIONS (FT.)		2,300	800	3
EMISSIONS REDUCTION FACTOR FOR FLANGES		Per Plant		
EMISSIONS REDUCTION FACTOR FOR ALL OTHER COMPONENTS		LENGTH	WDTH	HT
		767	800	3

PLANT FUGITIVES EMISSIONS

COMP	FACTOR LB/HR	FACTOR LB/DAY	QUANTITY	SERVICE HRS PER YR
VALVES				
GAS SERVICE	0.00992	0.23808	500	8760
LIGHT LIQUID	0.0055	0.132	500	8760
HEAVY LIQUID	0.00002	0.00048	0	8760
PUMPS				
LIGHT LIQUID	0.02866	0.68784	10	8760
HEAVY LIQUID	0.00113	0.02712	0	8760
FLANGES				
GAS SERVICE	0.00086	0.02064	1200	8760
LIGHT LIQUID	0.00024	0.00576	1200	8760
HEAVY LIQUID	0.00000	0.00002	0	8760
OPEN LINES	0.00441	0.10584	0	8760
RELIEF VALVES	0.01946	0.46704	40	8760
COMPRESSORS				
GAS SERVICE	0.01946	0.46704	20	8760
HEAVY LIQUID	0.00007	0.00168	0	8760
SAMPLE CNNCTNS	0.01946	0.46704	30	8760
CONNECTORS				
GAS SERVICE	0.00046	0.01104	2000	8760
LIGHT LIQUID	0.00046	0.01104	200	8760
HEAVY LIQUID	0.00024	0.00576	0	8760
TOTAL				

RAMSEY GAS PLANT INLET GAS ANALYSIS

GAS COMPONENT	MOLE %	MWT	WT %	MWT
METHANE	75.488	16.04	54.213	12.108
ETHANE	10.503	30.07	14.141	3.158
VOC-u	9.428	55.51	23.431	5.233
CO2	3.448	44.01	6.794	1.517
N2	1.133	28.01	1.421	0.317
H2S	0.0002	34.08	0.000	0.000
TOTAL	100.00			22.335

EMISSION FACTORS
LB/(HR-SOURCE)

COMPONENT	METHANE	ETHANE	VOC	CO2	N2	H2S
CONNECTORS						
GAS SERVICE	0.00025	0.00007	0.00011	0.00003	0.00001	0
LIGHT LIQUID	0.00025	0.00007	0.00011	0.00003	0.00001	0
HEAVY LIQUID	0.00013	0.00003	0.00006	0.00002	0.00000	0
VALVES						
GAS SERVICE	0.00538	0.00140	0.00232	0.00067	0.00014	3.027E-08
LIGHT LIQUID	0.00298	0.00078	0.00129	0.00037	0.00008	1.678E-08
HEAVY LIQUID	0.00001	0.00000	0.00000	0.00000	0.00000	6.103E-11
PUMPS						
LIGHT LIQUID	0.01554	0.00405	0.00672	0.00195	0.00041	8.746E-08
HEAVY LIQUID	0.00061	0.00016	0.00026	0.00008	0.00002	3.448E-09
FLANGES						
GAS SERVICE	0.00047	0.00012	0.00020	0.00006	0.00001	2.624E-09
LIGHT LIQUID	0.00013	0.00003	0.00006	0.00002	0.00000	7.324E-10
HEAVY LIQUID	0.00000	0.00000	0.00000	0.00000	0.00000	2.441E-12
OPEN LINES	0.00239	0.00062	0.00103	0.00030	0.00006	1.346E-08
RELIEF VALVES	0.01055	0.00275	0.00456	0.00132	0.00028	5.939E-08
COMPRESSORS						
GAS SERVICE	0.01055	0.00275	0.00456	0.00132	0.00028	5.939E-08
HEAVY LIQUID	0.00004	0.00001	0.00002	0.00000	0.00000	2.136E-10
SAMPLE CNNCTNS	0.01055	0.00275	0.00456	0.00132	0.00028	5.939E-08

RAMSEY FUGITIVE EMISSIONS FUGITIVES

COMPONENT	VALVES GAS TPY	VALVES LIGHT LQD TPY	VALVES HVY LQD TPY	TOTAL
METHANE	11.778	6.530	0.000	18.307
ETHANE	3.072	1.703	0.000	4.775
VOC	5.090	2.822	0.000	7.913
CO2	1.476	0.818	0.000	2.294
N2	0.309	0.171	0.000	0.480
H2S	0.000	0.000	0.000	0.000
TOTAL	21.725	12.045	0.000	

COMPONENT	PUMPS LIGHT LQD TPY	PUMPS HEAVY LQD TPY	CONNECTORS GAS TPY	CONNECTORS LIGHT LIQUID TPY	CONNECTORS HEAVY LIQUID TPY	TOTAL
METHANE	0.681	0.000	2.185	0.218	0.000	3.084
ETHANE	0.178	0.000	0.570	0.057	0.000	0.804
VOC	0.294	0.000	0.944	0.094	0.000	1.333
CO2	0.085	0.000	0.274	0.027	0.000	0.386
N2	0.018	0.000	0.057	0.006	0.000	0.081
H2S	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	1.255	0.000	4.030	0.403	0.000	

COMPONENT	FLANGES GAS TPY	FLANGES LIGHT LQD TPY	FLANGES HVY LQD TPY	TOTAL
METHANE	2.450	0.684	0.000	3.134
ETHANE	0.639	0.178	0.000	0.818
VOC	1.059	0.296	0.000	1.355
CO2	0.307	0.086	0.000	0.393
N2	0.064	0.018	0.000	0.082
H2S	0.000	0.000	0.000	0.000
TOTAL	4.520	1.261	0.000	

COMPONENT	OPEN LINES TPY	RELIEF VALVES TPY	SAMPLING CONNECT TPY	TOTAL
METHANE	0.000	1.848	1.386	3.235
ETHANE	0.000	0.482	0.362	0.844
VOC	0.000	0.799	0.599	1.398
CO2	0.000	0.232	0.174	0.405
N2	0.000	0.048	0.036	0.085
H2S	0.000	0.000	0.000	0.000
TOTAL	0.000	3.409	2.557	

COMPONENT	COMPRESSORS GAS SERVICE TPY	COMPRESSORS HEAVY SERVICE TPY	TOTAL
METHANE	0.924	0.000	0.924
ETHANE	0.241	0.000	0.241
VOC	0.399	0.000	0.399
CO2	0.116	0.000	0.116
N2	0.024	0.000	0.024
H2S	0.000	0.000	0.000
TOTAL	1.705	0.000	

PLANT FUGITIVE EMISSION
SUMMARY SHEET

COMPONENT	**METHANE**	**ETHANE**	**VOC**	**CO2**	**N2**	**H2S**
VALVES						
GAS SERVICE	11.778	3.072	5.090	1.476	0.309	0.000
LIGHT LIQUID	6.530	1.703	2.822	0.818	0.171	0.000
HEAVY LIQUID	0.000	0.000	0.000	0.000	0.000	0.000
PUMPS						
LIGHT LIQUID	0.681	0.178	0.294	0.085	0.018	0.000
HEAVY LIQUID	0.000	0.000	0.000	0.000	0.000	0.000
FLANGES						
GAS SERVICE	2.450	0.178	1.059	0.307	0.064	0.000
LIGHT LIQUID	0.684	0.178	0.296	0.086	0.018	0.000
HEAVY LIQUID	0.000	0.000	0.000	0.000	0.000	0.000
OPEN LINES	0.000	0.000	0.000	0.000	0.000	0.000
RELIEF VALVES	1.848	0.482	0.799	0.232	0.048	0.000
COMPRESSORS						
GAS SERVICE	0.924	0.241	0.399	0.116	0.024	0.000
HEAVY LIQUID	0.000	0.000	0.000	0.000	0.000	0.000
SAMPLE CONNECTIONS	1.386	0.362	0.599	0.174	0.036	0.000
TOTAL (TPY)	**26.281**	**6.394**	**11.359**	**3.294**	**0.689**	**0.000**
REDUCTION FCTR						
TOTAL (TPY)	**26.281**	**6.394**	**11.359**	**3.294**	**0.689**	**0.000**

TOTAL TOC EMISSIONS (TPY)	47.328
TOTAL VOC EMISSIONS (TPY)	11.359

Per Plant	Lbs/Hour	tpy
FUG-4	0.864	3.786
FUG-5	0.864	3.786
FUG-6	0.864	3.786

SPECIATED SUMMARY

RAMSEY GAS PLANT INLET PIPELINE QUALITY GAS ANALYSIS

COMPOUND	NATURAL GAS MOL%	MOL. WT.	CALC. MOL. WT.	CALC. WT. %	VOC (NMNE) EMISSIONS 0.864 LBS/HR	3.786 TPY
BENZENE	0.000%	78.110				
BUTANE	2.411%	58.120				
CO		28.000	0.0000	0.0000	0.000	0.000
CO2	3.448%	44.010	1.5175	7.5218	0.065	0.285
ETHANE	10.503%	30.070	3.1583	15.6549	0.135	0.593
ETHTLBENZ	0.000%	106.160	0.0000	0.0000	0.000	0.000
H2S	0.0002%	34.076	0.0001	0.0003	0.000	0.000
HEXANES	0.921%	86.178	0.7937	3.9342	0.034	0.149
METHANE	75.488%	16.040	12.1083	60.0185	0.519	2.273
N2	1.133%	28.013	0.3174	1.5732	0.014	0.060
NOX		46.010	0.0000	0.0000	0.000	0.000
PENTANE	0.928%	72.151				
PM10		0.000	0.0000	0.0000	0.000	0.000
PROPANE	5.168%	44.100	2.2791	11.2970	0.098	0.428
SO2		64.060	0.0000	0.0000	0.000	0.000
TOLUENE	0.000%	92.130	0.0000	0.0000	0.000	0.000
TSP		0.000	0.0000	0.0000	0.000	0.000
XYLENE	0.000%	106.160	0.0000	0.0000	0.000	0.000
VOC-U		97.500	0.0000	0.0000	0.000	0.000
	100.00%		20.1742	100.0000	0.864	3.786

VOC-NMNE EMISSIONS (LBS/HR) 0.132

ESTIMATED CO2e POTENTIAL TO EMIT (PTE) EMISSIONS
USING
40 CFR 98 EMISSION FACTORS

Facility: Ramsey Gas Plant

Unit Description

Fugitives	EMISSIONS			
	CO_2	**CH_4**	**N_2O**	**CO_2e**
	TPY	TPY	TPY	TPY
VALVES	2.29	18.31	0.000	**460**
PUMPS	0.09	0.7	0.000	**17**
FLANGES	0.39	3.1	0.000	**79**
OPEN LINES	0.00	0.00	0.000	**0**
RELIEF VALVES	0.23	1.85	0.000	**46**
COMPRESSORS	0.12	0.92	0.000	**23**
SAMPLE CONNECTIONS	0.17	1.39	0.000	**35**
			TOTAL	**556**

REGENERATIVE THERMAL OXIDIZER (RTO) EMISSIONS

RAMSEY GAS PLANT EXPANSION
Nuevo Midstream, LLC
1/15/2014

RTO START-UP EMISSIONS

DESIGN RATING

ITEMS / EPN	RTO-4	RTO-5
UTILIZATION PERCENTAGE	0.27%	0.27%
HEAT INPUT RATING (MMBTU/HR)	8	8
THERMAL EFFICIENCY	95%	95%
HEAT INPUT RATING ADJUSTED FOR EFFICIENCY?	YES	YES
FUEL HEAT CONTENT (BTU/SCF)	1077	1077
FUEL CONSUMPTION (MMSCF/YR)	0.2	0.2
HEAT INPUT (MMBTU/YR)	66,576	66,576
EXHAUST TEMPERATURE, T (F)=	150	150
PRESSURE, P (PSIA) =	14.7	14.7
THE RATIO OF O2 / CO2 =	1.925	1.925
THE RATIO OF H2O / CO2 =	1.85	1.85
STACK DIAMETER, (FT) =	4.5	4.5
STACK HEIGHT	40	40

AP-42 EMISSION FACTORS (UNCONTROLLED) EXCEPT FOR NO_X (LOW NO_X BURNER) -Tables 1.4-1 & 1.4-2:

	LBS/MMSCF
CO	84
NO_X	50
TOC	11
SO_2	0.6
PM (Total)	7.6
VOC	5.5

Conservatively assume that each RTO is started up once per month and that the start-up period lasts for 2 hours.

HOURS OF OPERATION

MONTH	AVAILABLE HRS/MONTH	EPN:	RTO-4 (HRS)	RTO-5 (HRS)
JAN	744		2	2
FEB	672		2	2
MAR	744		2	2
APRL	720		2	2
MAY	744		2	2
JUNE	720		2	2
JULY	744		2	2
AUG	744		2	2
SEPT	720		2	2
OCT	744		2	2
NOV	720		2	2
DEC	744		2	2
TOTAL	8,760.00		24	24

AP-42 EMISSIONS -- LBS/HR

COMPOUND	EPN:	RTO-4	RTO-5
CO		0.624	0.624
NO_X		0.371	0.371
TOC		0.082	0.082
VOC		0.041	0.041
SO_2		0.004	0.004
PM (Total)		0.056	0.056

AP-42 EMISSIONS -- TONS/YR

COMPOUND	RTO-4	RTO-5
CO	0.007	0.007
NO_X	0.004	0.004
TOC	0.001	0.001
VOC	0.000	0.000
SO_2	0.000	0.000
PM (Total)	0.001	0.001

During any downtime for the RTOs, the amine still vents will be routed to the emergency flare (EPN F-2). See emission calculations

UNCONTROLLED EMISSIONS FROM AMINE STILL VENT, PER UNIT

Mass Flow to RTO	**lb/h**	tpy	Molar Flow lbmol/h	Std. Vapor Volumetric Flow, MMSCFD
Nitrogen	0.08	0.33	0.003	0.0248
Hydrogen Sulfide	7.65	33.52	0.225	2.0425
Carbon Dioxide	37,594.44	164,663.65	854.235	7,770.1186
Methane	31.63	138.52	1.971	17.9313
Ethane	19.93	87.30	0.663	6.0296
Propane	9.82	43.03	0.223	2.0265
Isobutane	0.91	3.98	0.016	0.1421
Butane	3.82	16.72	0.066	0.5975
Isopentane	0.25	1.10	0.003	0.0316
Pentane	0.51	2.25	0.007	0.0647
Hexane	0.82	3.59	0.010	0.0866
Water	1,205.81	5,281.46	66.933	608.8210
MDEA	0.00	0.00	0.000	0.0000
DEA	0.00	0.00	0.000	0.0000
Ethylene Glycol	0.00	0.00	0.000	0.0000
TEG	0.00	0.00	0.000	0.0000

8407.92 Total Acid Gas Flow, MSCFD

The Mass and Volume Flow rates are from a ProMax Analysis dated 11/11/13

Estimated
CO2 taken by Kinder Morgan
42%
68,545 tpy per unit
137,091 tpy Total
Captital Cost
$15,000,000
Cost per ton, over 7-y per ton
$31.26

Total Acid Gas Fl MSCFD Total
16816
Proposed to be taken by Kinder Morgan
7 MMSCFD
7000 MSCFD
42%

CONTROLLED EMISSIONS BY RTOs

Parameter	EPN	RTO-4	RTO-4	RTO-4	RTO-5	RTO-5	RTO-5
	DRE (%)	Inlet (lb/hr)	Controlled lb/h	Controlled TPY	Inlet (lb/hr)	Controlled lb/h	Controlled TPY
Hydrogen Sulfide	99	7.653	0.077	0.335	7.653	0.077	0.335
Methane	99	31.625	0.316	1.385	31.625	0.316	1.385
Ethane	99	19.932	0.199	0.873	19.932	0.199	0.873
Propane	99	9.824	0.098	0.430	9.824	0.098	0.430
Isobutane	99	0.908	0.009	0.040	0.908	0.009	0.040
Butane	99	3.818	0.038	0.167	3.818	0.038	0.167
Isopentane	99	0.251	0.003	0.011	0.251	0.003	0.011
Pentane	99	0.513	0.005	0.022	0.513	0.005	0.022
Hexane$^+$	99	0.820	0.008	0.036	0.820	0.008	0.036
MDEA	99	0.000	0.000	0.000	0.000	0.000	0.000
DEA	99	0.000	0.000	0.000	0.000	0.000	0.000
Ethylene Glycol	99	0.000	0.000	0.000	0.000	0.000	0.000
TEG	99	0.000	0.000	0.000	0.000	0.000	0.000
VOC		16.134	0.161	0.707	16.134	0.161	0.707
HAPs		0.820	0.008	0.036	0.820	0.008	0.036

Calculated assuming that the RTOs operate 8760 hrs/yr

The Destruction Efficiency was provided by the vendor

Controlled SO_2 Emissions

Emission Rate (lb/hr) = [H_2S inlet (lb/hr) - H_2S Outlet (lb/hr)] x [SO_2 Molecular Weight (MW) (lb/lb-mol) ÷ H_2S MW (lb/lb-mol)]

SO_2 Emission Rate (lb/hr) = 14.241

SO_2 Emission Rate (TPY) = 62.375

	EPN	RTO-4	RTO-5
H_2S inlet (lb/hr)		7.653	7.653
H_2S outlet (lb/hr)		0.077	0.077
SO_2 MW (lb/lb-mol)		64.06	64.06
H_2S MW (lb/lb-mol)		34.08	34.08
SO_2 emissions (lb/hr)		14.241	14.241
SO_2 emissions (TPY)		62.375	62.375

Controlled CO, NO_x and SO_2 Emissions

Stack Flowrate, scfm	22,034
Stack flowrate, scf/hr	1,322,040
Exhaust temperature, F	200
Exhaust temperature, R	661

Controlled NOx Emissions

NOx emission factor, lb/MMBTU natural gas burned	0.1	Vendor data
Gas burned, MMBtu/hr	4.546	Vendor data
Gas Burned/year	39,823	
NOx emissions, lb/hr	0.455	
NOx emissions, tpy	1.991	

Controlled CO and SO_2 Emissions

CO Emission Factor, ppm	50	Vendor data
SOx Emission Factor, ppm	272	Vendor data

Stack flowrate (lb-mol/hr) = Pressure (atm) x Stackflowrate (scf/hr)/Gas constant (ft^3 x atm/R/lb-mol)/Temperature R

Stack flowrate (lb-mol/hr) = 1 x 1,322,040 /R x lb-mol/(0.730241 ft3 x atm)// 660.670

Stack flowrate (lb-mol/hr) = 2,740

CO Emissions, lbs/hr= Stack flowrate(lb-mol/hr) x Stack gas concentration (ppm)/1,000,000 x Molecular weight (lb/lb-mol)

CO Emissions, lbs/hr=	**3.84**
CO Emissions, TPY	**16.80**

SOx Emissions, lbs/hr= Stack flowrate(lb-mol/hr) x Stack gas concentration (ppm)/1,000,000 x Molecular weight (lb/lb-mol)

SOx Emissions, lbs/hr=	**0.01**
SOx Emissions, TPY	**0.05**

Total Emissions		RTO-4		RTO-5	
		Lbs/Hour	tpy	Lbs/Hour	tpy
	VOC	0.202	0.707	0.202	0.707
	NOX	0.826	1.996	0.826	1.996
	CO	4.460	16.811	4.460	16.811
	PM10/2.5	0.056	0.001	0.056	0.001
	SO2	14.293	62.426	14.293	62.426
	Total HAP	0.008	0.036	0.008	0.036

CALCULATE EXHAUST STACK VELOCITY

	RTO-4
VOLUME (ACF/HR) =	1,089,766.0
VOLUME (ACF/S) =	302.7
STACK DIAMETER (FT) =	4.5
STACK CROSS-SECTIONAL AREA=	63.62
EXHAUST VELOCITY (f/s) =	4.76

AS AN EXAMPLE:

TO CALCULATE ESTIMATED CO2 EMISSIONS AND % VOLUMES.

THE FOLLOWING CONDITIONS APPLY FOR CALCULATION OF EXHAUST GAS VOLUMES:

V(FT3/HR) = mRT/MP

EXHAUST TEMPERATURE, T (F) =	150
PRESSURE, P (PSIA) =	14.7
MASS FLOW RATE, m (LBS/HR) =	0
MOL. WT. , m (LBS/LB-MOL) =	27.13
GAS CONSTANT, R =	10.73

THE STOCHIOMETRIC EQN. DEPICTS THE PRIMARY COMBUSTION REACTION:

40 CH 3.7 + 77 O2 = 40 CO2 + 74 H2O

THE RATIO OF O2 / CO2 =	77/40 =	1.925
THE RATIO OF H2O / CO2 =	74/40 =	1.85

EPN: **RTO-4**

COMPOUND	Input Flow Lbs/Hr	MOL. WT.	FUEL GAS INPUT MOL/Hour	**EXHAUST CO2** EMISSIONS MOL/Hour	EMISSIONS MOL/Hour	EMISSIONS LBS/HR	FLOW RATE FT3/HR	ESTIM. VOL. %	FLWRATE TPY
BENZENE	0.00	78.1	0.0000		0.0000	0.000	0.00	0.00	0.00
BUTANE	4.73	58.12	0.0813	0.3253	0.0001	0.005	0.04	0.00	0.02
CO	0.00	28			3.8231	4.460	70.93	0.01	19.54
CO2	37,594.44	44.01	854.2250	854.2250	859	37,788.135	382,310.58	35.08	165,512.03
CYCLOHEXANE	0.00	84.16	0.0000	0.0000	0.0000	0.000	0.00	0.00	0.00
ETHANE	19.93	30.07	0.6629	1.3257	0.0007	0.020	0.30	0.00	0.09
ETHYLBENZENE	0.00	106.16	0.0000		0.0000	0.000	0.00	0.00	0.00
FORMALDEHYD	0.00	30	0.0000	0.0000		0.000	0.00	0.00	0.00
H2S	7.65	34.076	0.2246		0.0000	0.000	0.00	0.00	0.00
HEXANES	0.82	86.17	0.0095	0.0571	0.0000	0.001	0.00	0.00	0.00
METHANE	31.63	16.04	1.9716	1.9716	0.0020	0.032	0.88	0.00	0.14
METHANOL	0.00	32.04	0.0000	0.0000	0.0000	0.000	0.00	0.00	0.00
N2	0.08	28.013	0.0027	0.0000	0	0.076	1.21	0.00	0.33
NOX	0.00	46.01	0.0000	0.0000		0.826	7.99	0.00	3.62
PENTANE	0.76	72.15	0.0106	0.0529	0.0000	0.001	0.00	0.00	0.00
PM10	0.00			0.0000	0.0000	0.000			0.00
PROPANE	9.82	44.09	0.2228	0.6685	0.0002	0.010	0.10	0.00	0.04
SO2	0.00	64.06	0.0000	0.0000	0.2090	14.293	99.35	0.01	62.60
TEG	0.00	150.18	0.0000	0.0000	0.0000	0.000	0.00	0.00	0.00
TOLUENE	0.00	92.13	0.0000		0.0000	0.000	0.00	0.00	0.00
TSP	0.00			0.0000		0.000			0.00
VOC-U	0.00	97.5	0.0000	0.0000		0.000	0.00	0.00	0.00
WATER VAPOR	1,205.81	18	66.9896	0.0000	1,588	28,592.250	707,274.57	64.90	125,234.05
XYLENE	0.00	106.16	0.0000		0.0000	0.000	0.00	0.00	0.00
	38875.68		924	859	2,451	66,400.109	1,089,765.95	100.00	290,832.48

ESTIMATED CO_2e POTENTIAL TO EMIT (PTE) EMISSIONS USING 40 CFR 98 EMISSION FACTORS AND PROCESS DATA

Facility: Ramsey Gas Plant

Unit Description

	Heat Input			**Emission Factors**		
Fuel Emissions	**Heat Input Rating**	**Hours of Operation**	**Maximum (MMBtu /yr)**	**CO_2**	**CH_4**	**N_2O**
	MMBtu/hr			kg/MMBtu[1]	kg/MMBtu[2]	kg/MMBtu[2]
RTO-4	8	24	192	53.02	1.00E-03	1.00E-04
RTO-5	8	24	192	53.02	1.00E-03	1.00E-04

POTENTIAL EMISSIONS

	CO_2	**CH_4**	**N_2O**	**CO_2e**	**CO_2**	**CH_4**	**N_2O**	**CO_2e**
	lbs/hr	lbs/hr	lbs/hr	lbs/hr	TPY	TPY	TPY	TPY
RTO-4	935.1	0.02	0.002	**936**	11.2	0.0002	0.00002	**11**
RTO-5	935.1	0.02	0.002	**936**	11.2	0.0002	0.00002	**11**
			SUBTOTAL	**1,872**	lbs/hr		**SUBTOTAL**	**22 TPY**

Amine Still Vent Acid Gas Flow Rate

Acid Gas Flow Rate[3]

A-4		8.41	MMSCF/D
A-5		8.41	MMSCF/D
	Total	16.82	MMSCF/D
Acid Gas Transferred to Kinder Morgan[4]		7.00	MMSCF/D
		42%	of total
	Transfer is hard-piped from process -	100%	Capture

BASE CASE

Potential Amine Still Vent Acid Gas Combustion Emissions - RTO Control Only

	CO_2	CH_4	C_2H_6	C_3H_8	C_4H_{10}	C_5H_{12}	C_6H_{14}
A-4	37,594	31.63	19.93	9.82	4.73	0.76	0.82
A-5	37,594	31.63	19.93	9.82	4.73	0.76	0.82
Totals	75,189	63.25	39.86	19.65	9.45	1.53	1.64
Mole Weight	44.01	16.04	30.07	44.10	58.12	72.15	86.18
Mole Ratio	1	1	2	3	4	5	6
	Net CO_2 Emissions After Combustion, lbs.hr				Combustion Efficiency =		99.0%
	75,189	171.78	115.53	58.24	28.34	4.61	4.98

EMISSIONS

	CO_2	**CH_4**	**N_2O**	**CO_2e**	**CO_2**	**CH_4**	**N_2O**	**CO_2e**
	lbs/hr	lbs/hr	lbs/hr	lbs/hr	TPY	TPY	TPY	TPY
Subtotals	75,572	0.63	0.00	**75,586**	331,007	2.77	0	**331,065**
TOTALS				**77,458**				**331,088 TPY**
Per Unit	38,721	0.33	0.002	38,729	165,515	1.39	0.000	165,543.793
				1,858,984	Lbs/day			
			Acid Gas Flow Rate	9,816	MSCF/day			

Conservative Emission Factor 190 lbs/MSCF

WHEN OFFSITE TRANSFER IS AVAILABLE - CSS CASE

Potential Amine Still Vent Acid Gas Combustion Emissions - RTO plus CSS

Transferred to Kinder Morgan	31,299	26.33	16.59	8.18	3.93	0.64	0.68
Net Emissions	43,890	36.92	23.27	11.47	5.52	0.89	0.96
Mole Weight	44.01	16.04	30.07	44.10	58.12	72.15	86.18
Mole Ratio	1	1	2	3	4	5	6
	Net CO_2 Emissions After Combustion, lbs.hr				Combustion Efficiency =		99.0%
	43,890	100.27	67.44	34.00	16.54	2.69	2.90

EMISSIONS

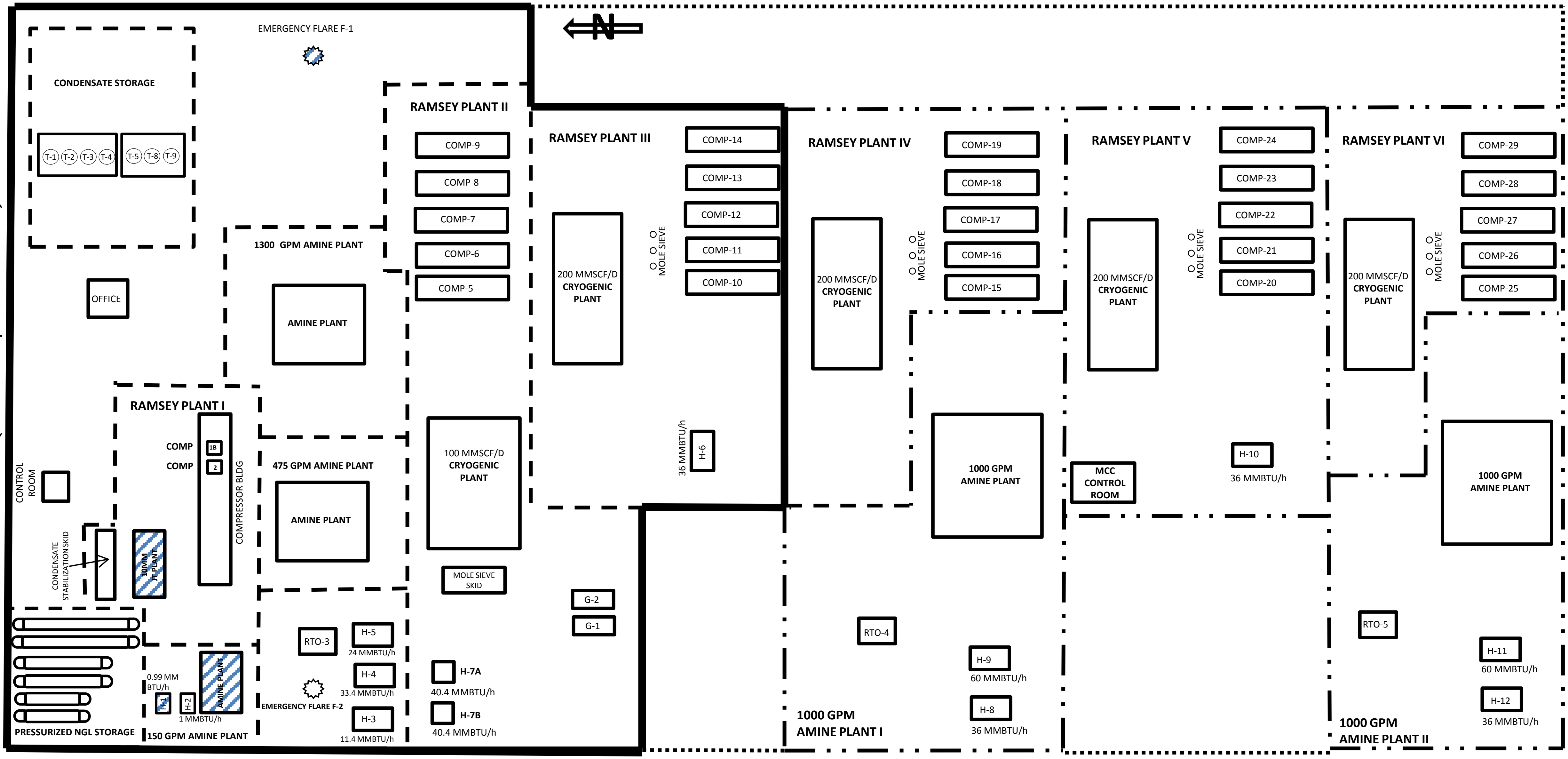
	CO_2	**CH_4**	**N_2O**	**CO_2e**	**CO_2**	**CH_4**	**N_2O**	**CO_2e**	
	lbs/hr	lbs/hr	lbs/hr	lbs/hr	TPY	TPY	TPY	TPY	
Subtotals	44,114	0.37	0.00	**44,121**	193,217	1.62	0	**193,251**	
TOTALS				**45,993**				**193,274**	**TPY**
Per Unit	22,992	0.20	0.002	22,997	96,620	0.81	0.000	96,636.836	

1,103,840 Lbs/day

Acid Gas Flow Rate 9,816 MSCF/day

Conservative Emission Factor 120 lbs/MSCF

FIGURE 1
Ramsey Gas Plant Site Location Map
Nuevo Midstream LLC



LEGEND

- CURRENTLY PERMITTED FACILITIES
- CURRENTLY PERMITTED UNITS
- RAMSEY FACILITY EXPANSION
- PLANT BOUNDARIES
- OUT OF SERVICE UNITS

FIGURE 2

RAMSEY FACILITY PLOT PLAN

Nuevo Midstream LLC

Reeves County, Texas

Not To Scale

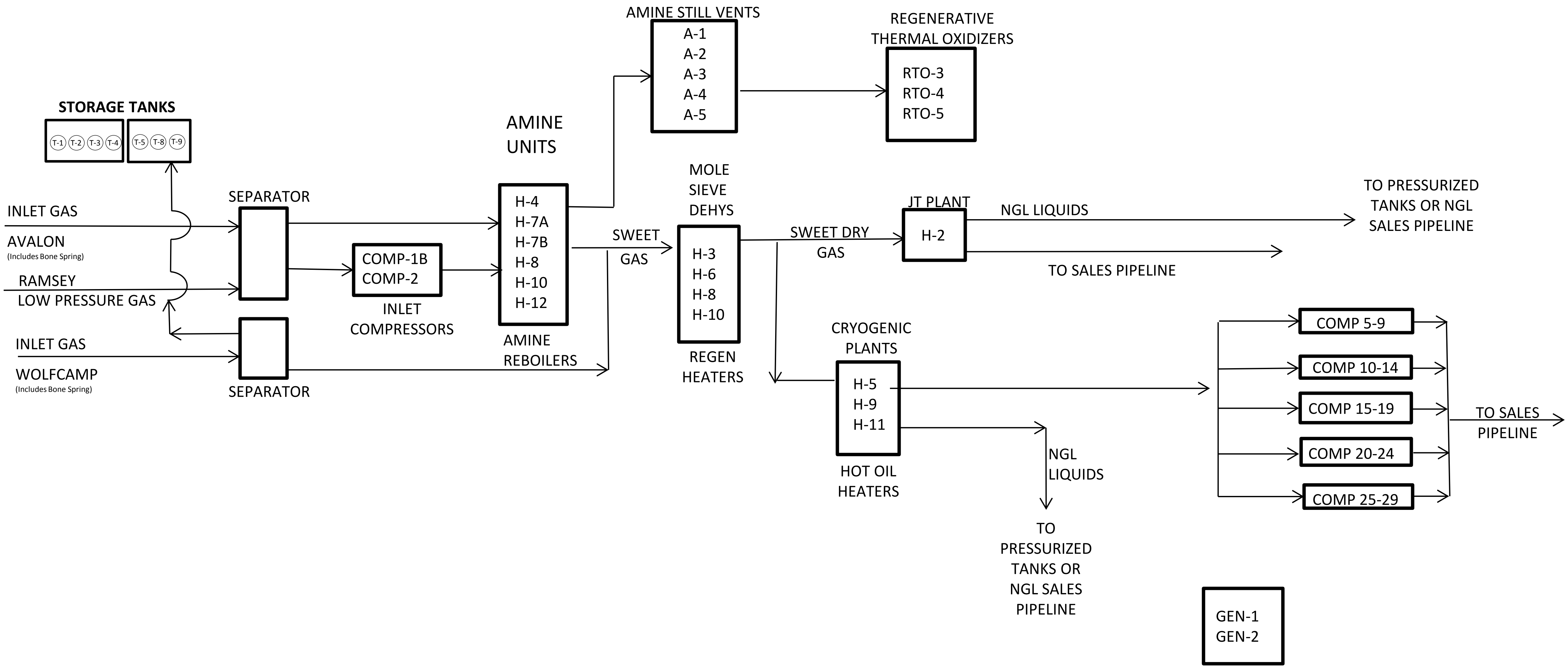


FIGURE 3

PROCESS FLOW DIAGRAM
Nuevo Midstream LLC
Reeves County, Texas

SECTION 6

LABORATORY SERVICES
Natural Gas Analysis

www.permianls.com

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Avalon Inlet
Example
Analysis 1

For:	Nuevo Midstream Attention: Clint Cone 1331 Lamar, Suite 1450 Houston, Texas 77450	Sample: Identification: Company: Lease: Plant:	Sta. # 01605215 Mewbourne Red Hills West Torch

Sample Data:	Date Sampled	7/4/2013		
	Analysis Date	7/8/2013		
	Pressure-PSIA	163	Sampled by:	D. Stevens/Gas Meas.
	Sample Temp F	86.7	Analysis by:	Vicki McDaniel
	Atmos Temp F	92		

H2S = 5 PPM

Component Analysis

		Mol Percent	GPM
Hydrogen Sulfide	H2S	0.0005	
Nitrogen	N2	1.5460	
Carbon Dioxide	CO2	7.2080	
Methane	C1	73.1025	
Ethane	C2	9.4990	2.534
Propane	C3	5.1330	1.411
I-Butane	IC4	0.6530	0.213
N-Butane	NC4	1.5640	0.492
I-Pentane	IC5	0.4090	0.149
N-Pentane	NC5	0.4160	0.150
Hexanes Plus	C6+	0.4690	0.203
		100.0000	5.152

REAL BTU/CU.FT.	
At 14.65 DRY	1165.7
At 14.65 WET	1145.3
At 14.696 DRY	1169.3
At 14.696 WET	1149.4
At 14.73 DRY	1172.0
At 14.73 Wet	1151.8

Specific Gravity
Calculated 0.7863

Molecular Weight 22.7734

LABORATORY SERVICES
Natural Gas Analysis

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Avalon Inlet
Example
Analysis 2

For:	Nuevo Midstream Attention: Clint Cone 1331 Lamar, Suite 1450 Houston, Texas 77450	Sample: Identification: Company: Lease: Plant:	Sta. # 01605212 Conoco CTB East Torch

Sample Data:	Date Sampled	7/4/2013		
	Analysis Date	7/8/2013		
	Pressure-PSIA	157	Sampled by:	D. Stevens/Gas Meas.
	Sample Temp F	105.7	Analysis by:	Vicki McDaniel
	Atmos Temp F	88		

H2S = 2 PPM

Component Analysis

		Mol Percent	GPM
Hydrogen Sulfide	H2S	0.0002	
Nitrogen	N2	1.5620	
Carbon Dioxide	CO2	8.1690	
Methane	C1	72.5948	
Ethane	C2	9.1860	2.450
Propane	C3	4.9340	1.356
I-Butane	IC4	0.6250	0.204
N-Butane	NC4	1.4720	0.463
I-Pentane	IC5	0.4010	0.146
N-Pentane	NC5	0.4360	0.158
Hexanes Plus	C6+	0.6200	0.268
		100.0000	5.045

REAL BTU/CU.FT.	
At 14.65 DRY	1154.3
At 14.65 WET	1134.2
At 14.696 DRY	1157.9
At 14.696 WET	1138.2
At 14.73 DRY	1160.6
At 14.73 Wet	1140.6

Specific Gravity
Calculated 0.7947

Molecular Weight 23.0171

LABORATORY SERVICES
Natural Gas Analysis

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575.397.3713 2609 W Marland Hobbs NM 88240

Wolfcamp
Inlet

For:	Nuevo Midstream LLC Attention: Clint Cone 1331 Lamar, Suite 1450 Houston, Texas 77450	Sample: Identification: Company: Lease: Plant:	Sta. # 01605233 Bold Johnson 30 Nuevo Midstream LLC

Sample Data:	Date Sampled	7/19/2013	1:00 PM		
	Analysis Date	7/19/2013			
	Pressure-PSIA	117		Sampled by:	Taylor Ridings
	Sample Temp F	108		Analysis by:	Vicki McDaniel
	Atmos Temp F	0			

H2S = 0.2 PPM

Component Analysis

		Mol Percent	GPM
Hydrogen Sulfide	H2S		
Nitrogen	N2	0.5920	
Carbon Dioxide	CO2	0.2740	
Methane	C1	78.8720	
Ethane	C2	10.6720	2.847
Propane	C3	4.4740	1.229
I-Butane	IC4	0.8650	0.282
N-Butane	NC4	1.5980	0.502
I-Pentane	IC5	0.5100	0.186
N-Pentane	NC5	0.5590	0.202
Hexanes Plus	C6+	1.5840	0.686
		100.0000	5.935

REAL BTU/CU.FT.	
At 14.65 DRY	1303.5
At 14.65 WET	1280.8
At 14.696 DRY	1307.6
At 14.696 WET	1285.3
At 14.73 DRY	1310.6
At 14.73 Wet	1287.9

Specific Gravity
Calculated 0.7527

Molecular Weight 21.8002

LABORATORY SERVICES
Natural Gas Analysis

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Bone Spring
Inlet

575.397.3713 2609 W Marland Hobbs NM 88240

For:	Nuevo Midstream Attention: Clint Cone 1331 Lamar, Suite 1450 Houston, Texas 77450	Sample: Identification: Company: Lease: Plant:	Sta. # 01605205 Aldren Torch

Sample Data:	Date Sampled	6/27/2013		
	Analysis Date	7/3/2013		
	Pressure-PSIA	138	Sampled by:	D. Stevens/Gas Meas.
	Sample Temp F	105.1	Analysis by:	Vicki McDaniel
	Atmos Temp F	91		

H2S = 0.2 PPM

Component Analysis

		Mol Percent	GPM
Hydrogen Sulfide	H2S		
Nitrogen	N2	1.1020	
Carbon Dioxide	CO2	0.3270	
Methane	C1	76.8140	
Ethane	C2	11.6740	3.114
Propane	C3	5.9070	1.623
I-Butane	IC4	0.7580	0.247
N-Butane	NC4	1.8610	0.585
I-Pentane	IC5	0.3990	0.146
N-Pentane	NC5	0.4980	0.180
Hexanes Plus	C6+	0.6600	0.286
		100.0000	6.181

REAL BTU/CU.FT.	
At 14.65 DRY	1287.1
At 14.65 WET	1264.7
At 14.696 DRY	1291.1
At 14.696 WET	1269.2
At 14.73 DRY	1294.1
At 14.73 Wet	1271.8

Specific Gravity
Calculated 0.7484

Molecular Weight 21.6749

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Ramsey
Residue, Used
For Fuel Gas

For:	Nuevo Midstream	Sample:	Sta. # 01607050
	Attention: Clint Cone	Identification:	Ramsey II Residue
	1331 Lamar, Suite 1450	Company:	Nuevo Midstream
	Houston, Texas 77450	Lease:	
		Plant:	Ramsey II

Sample Data:	Date Sampled	7/17/2013	2:30 PM		
	Analysis Date	7/18/2013			
	Pressure-PSIA	739.9		Sampled by:	Logan McIlroy
	Sample Temp F	99.1		Analysis by:	Vicki McDaniel
	Atmos Temp F	70			

H2S = 0

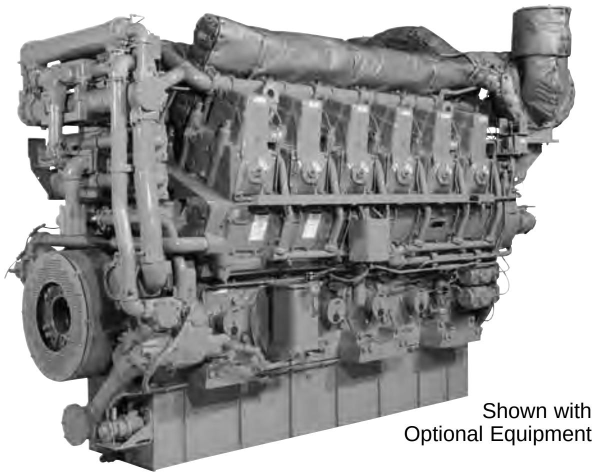
Component Analysis

		Mol Percent	GPM
Hydrogen Sulfide	H2S	0.0000	
Nitrogen	N2	2.0200	
Carbon Dioxide	CO2	0.1880	
Methane	C1	86.9110	
Ethane	C2	10.6370	2.837
Propane	C3	0.2440	0.067
I-Butane	IC4	0.0000	0.000
N-Butane	NC4	0.0000	0.000
I-Pentane	IC5	0.0000	0.000
N-Pentane	NC5	0.0000	0.000
Hexanes Plus	C6+	0.0000	0.000
		100.0000	2.904

REAL BTU/CU.FT.		Specific Gravity	
At 14.65 DRY	1071.4	Calculated	0.6179
At 14.65 WET	1052.7		
At 14.696 DRY	1074.8		
At 14.696 WET	1056.4	Molecular Weight	17.8973
At 14.73 DRY	1077.3		
At 14.73 Wet	1058.7		

G3612 LE Gas Petroleum Engine

2647-2823 bkW (3550-3785 bhp) 1000 rpm



Shown with
Optional Equipment

0.5 g/bhp-hr NOx or 0.7 g/bhp-hr NOx (NTE)

CAT® ENGINE SPECIFICATIONS

V-12, 4-Stroke-Cycle

Bore	300 mm (11.8 in.)
Stroke	300 mm (11.8 in.)
Displacement	254 L (15,528 cu. in.)
Aspiration	Turbocharged-Aftercooled
Digital Engine Management	
Governor and Protection	Electronic (ADEM™ A3)
Combustion	Low Emission (Lean Burn)
Engine Weight	
net dry (approx)	25,084 kg (55,300 lb)
Power Density	8.9 kg/kW (14.6 lb/hp)
Power per Displacement	14.9 bhp/L
Total Cooling System Capacity	734.4 L (194 gal)
Jacket Water	670 L (177 gal)
Aftercooler Circuit	64 L (17 gal)
Lube Oil System (refill)	1030 L (272 gal)
Oil Change Interval	5000 hours
Rotation (from flywheel end)	Counterclockwise
Flywheel Teeth	255

FEATURES

Engine Design
- Proven reliability and durability
- Ability to burn a wide spectrum of gaseous fuels
- Robust diesel strength design prolongs life and lowers owning and operating costs
- Broad operating speed range

Emissions
Meets U.S. EPA Spark Ignited Stationary NSPS Emissions for 2010/11 with the use of an oxidation catalyst

Lean Burn Engine Technology
Lean-burn engines operate with large amounts of excess air. The excess air absorbs heat during combustion reducing the combustion temperature and pressure, greatly reducing levels of NOx. Lean-burn design also provides longer component life and excellent fuel consumption.

Ease of Operation
- High-strength pan and rails for excellent mounting and stability
- Side covers on block allow for inspection of internal components

Advanced Digital Engine Management
ADEM A3 engine management system integrates speed control, air/fuel ratio control, and ignition/detonation controls into a complete engine management system. ADEM A3 has improved: user interface, display system, shutdown controls, and system diagnostics.

Full Range of Attachments
Large variety of factory-installed engine attachments reduces packaging time.

Testing
Every engine is full-load tested to ensure proper engine performance.

Gas Engine Rating Pro
GERP is a PC-based program designed to provide site performance capabilities for Cat® natural gas engines for the gas compression industry. GERP provides engine data for your site's altitude, ambient temperature, fuel, engine coolant heat rejection, performance data, installation drawings, spec sheets, and pump curves.

Product Support Offered Through Global Cat Dealer Network
More than 2,200 dealer outlets

Cat factory-trained dealer technicians service every aspect of your petroleum engine

Cat parts and labor warranty

Preventive maintenance agreements available for repair-before-failure options

S•O•S℠ program matches your oil and coolant samples against Caterpillar set standards to determine:
- Internal engine component condition
- Presence of unwanted fluids
- Presence of combustion by-products
- Site-specific oil change interval

Over 80 Years of Engine Manufacturing Experience
Over 60 years of natural gas engine production

Ownership of these manufacturing processes enables Caterpillar to produce high quality, dependable products
- Cast engine blocks, heads, cylinder liners, and flywheel housings
- Machine critical components
- Assemble complete engine

Web Site
For all your petroleum power requirements, visit www.catoilandgas.cat.com.

STANDARD EQUIPMENT

Air Inlet System
Air cleaner — standard duty
Inlet air adapter

Control System
A3 control system — provides electronic governing integrated with air/fuel ratio control and individual cylinder ignition timing control

Cooling System
Jacket water pump
Jacket water thermostats and housing
Aftercooler pump
Aftercooler water thermostats and housing
Single-stage aftercooler

Exhaust System
Dry wrapped exhaust manifolds
Vertical outlet adapter

Flywheel & Flywheel Housing
SAE standard rotation

Fuel System
Gas admission valves — electronically controlled fuel supply pressure

Ignition System
A3 control system — senses individual cylinder detonation and controls individual cylinder timing

Instrumentation
LCD display panel — monitors engine parameters and displays diagnostic codes

Lube System
Crankcase breathers — top mounted
Oil cooler
Oil filter
Oil pan drain valve

Mounting System
Engine mounting feet (six total)

Protection System
Electronic shutoff system with purge cycle
Crankcase explosion relief valves
Gas shutoff valve

Starting System
Air starting system

General
Paint — Cat yellow
Vibration dampers

OPTIONAL EQUIPMENT

Air Inlet System
Heavy-duty air cleaner with precleaners
Heavy-duty air cleaner with rain protection

Charging System
Charging alternators

Control System
Custom control system software — available for non-standard ratings, field programmable using flash memory

Cooling System
Expansion tank
Flexible connections
Jacket water heater

Exhaust System
Flexible bellows adapters
Exhaust expander
Weld flanges

Fuel System
Fuel filter
Gas pressure regulator
Flexible connection
Low energy fuel system
Corrosive gas fuel system

Ignition System
CSA certification

Instrumentation
Remote data monitoring and speed control
Compatible with Cat Electronic Technician (ET) and Data View
Communication Device — PL1000T/E
Display panel deletion is optional

Lube System
Air or electric motor-driven prelube
Duplex oil filter
LH or RH service
Lube oil makeup system

Mounting System
Mounting plates (set of six)

Power Take-Offs
Front stub shafts

Starting System
Air pressure reducing valve
Natural gas starting system

General
Engine barring device
Damper guard

TECHNICAL DATA

G3612 LE Gas Petroleum Engine — 1000 rpm

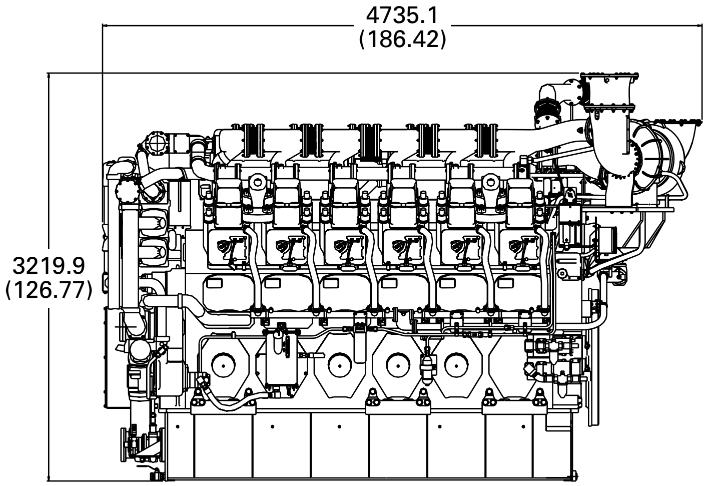
		DM5134-03	DM5309-06	DM5310-06	DM8607-02
Engine Power					
@ 100% Load	bkW (bhp)	2733 (3665)	2823 (3785)	2647 (3550)	2647 (3550)
@ 75% Load	bkW (bhp)	2049 (2749)	2117 (2839)	1985 (2663)	1985 (2663)
Engine Speed	rpm	**1000**	**1000**	**1000**	**1000**
Max Altitude @ Rated Torque and 38°C (100°F)	m (ft)	1219.2 (4000)	1219.2 (4000)	609.6 (2000)	304.8 (1000)
Speed Turndown @ Max Altitude, Rated Torque, and 38°C (100°F)	%	21	20	23	23
SCAC Temperature	°C (°F)	43 (110)	32 (90)	55 (130)	55 (130)
Emissions*					
NOx	g/bkW-hr (g/bhp-hr)	0.94 (0.7)	0.94 (0.7)	0.94 (0.7)	0.67 (0.5)
CO	g/bkW-hr (g/bhp-hr)	3.4 (2.5)	3.4 (2.5)	3.4 (2.5)	3.7 (2.75)
CO_2	g/bkW-hr (g/bhp-hr)	587 (438)	585 (436)	589 (439)	591 (441)
VOC**	g/bkW-hr (g/bhp-hr)	0.79 (0.59)	0.75 (0.56)	0.82 (0.61)	0.87 (0.65)
Fuel Consumption***					
@ 100% Load	MJ/bkW-hr (Btu/bhp-hr)	9.31 (6580)	9.28 (6561)	9.34 (6600)	9.38 (6629)
@ 75% Load	MJ/bkW-hr (Btu/bhp-hr)	9.7 (6856)	9.66 (6829)	9.74 (6883)	9.78 (6914)
Heat Balance					
Heat Rejection to Jacket Water					
@ 100% Load	bkW (Btu/min)	656 (37,336)	677 (38,539)	639 (36,379)	638 (36,338)
@ 75% Load	bkW (Btu/min)	576 (32,714)	594 (33,755)	546 (31,052)	548 (31,179)
Heat Rejection to Aftercooler					
@ 100% Load	bkW (Btu/min)	515 (29,299)	563 (32,045)	468 (26,661)	488 (27,783)
@ 75% Load	bkW (Btu/min)	281 (15,954)	310 (17,616)	252 (14,361)	264 (15,016)
Heat Rejection to Exhaust					
@ 100% Load	bkW (Btu/min)	2705 (153,813)	2743 (156,017)	2664 (151,486)	2673 (152,035)
@ 75% Load	bkW (Btu/min)	2152 (122,365)	2184 (124,184)	2132 (121,263)	2141 (121,731)
Exhaust System					
Exhaust Gas Flow Rate					
@ 100% Load	N•m³/bkW-hr (cfm)	690.14 (24,372)	705.85 (24,927)	674.20 (23,809)	682.15 (24,090)
@ 75% Load	N•m³/bkW-hr (cfm)	543.32 (19,187)	553.65 (19,552)	532.67 (18,811)	538.95 (19,033)
Exhaust Stack Temperature					
@ 100% Load	°C (°F)	453.30 (848)	448 (838)	459 (858)	448 (838)
@ 75% Load	°C (°F)	472.20 (882)	464 (867)	480 (896)	469 (876)
Intake System					
Air Inlet Flow Rate					
@ 100% Load	N•m³/bkW-hr (scfm)	265.78 (9386)	273.91 (9673)	257.66 (9099)	264.99 (9358)
@ 75% Load	N•m³/bkW-hr (scfm)	203.85 (7199)	210.00 (7416)	197.71 (6982)	203.34 (7181)
Gas Pressure	kPag (psig)	295-324 (42.8-47)	295-324 (42.8-47)	295-324 (42.8-47)	295-324 (42.8-47)

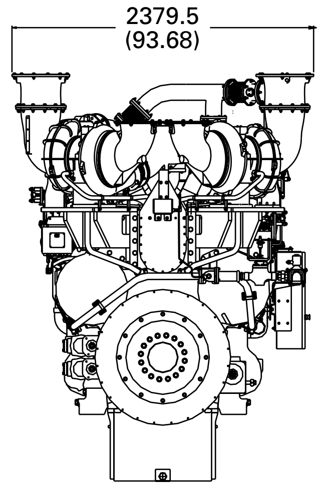
*at 100% load and speed, all values are listed as not to exceed

**Volatile organic compounds as defined in U.S. EPA 40 CFR 60, subpart JJJJ

***ISO 3046/1

GAS PETROLEUM ENGINE





DIMENSIONS		
Length	mm (in)	4735.1 (186.42)
Width	mm (in)	2379.5 (93.68)
Height	mm (in)	3219.9 (126.77)
Shipping Weight	kg (lb)	25,084 (55,300)

Note: General configuration not to be used for installation. See general dimension drawings for detail.

RATING DEFINITIONS AND CONDITIONS

Engine performance is obtained in accordance with SAE J1995, ISO3046/1, BS5514/1, and DIN6271/1 standards.

Transient response data is acquired from an engine/generator combination at normal operating temperature and in accordance with ISO3046/1 standard ambient conditions. Also in accordance with SAE J1995, BS5514/1, and DIN6271/1 standard reference conditions.

Conditions: Power for gas engines is based on fuel having an LHV of 33.74 kJ/L (905 Btu/cu ft) at 101 kPa (29.91 in. Hg) and 15° C (59° F). Fuel rate is based on a cubic meter at 100 kPa (29.61 in. Hg) and 15.6° C (60.1° F). Air flow is based on a cubic foot at 100 kPa (29.61 in. Hg) and 25° C (77° F). Exhaust flow is based on a cubic foot at 100 kPa (29.61 in g) and stack temperature.

8/7/2011

CATALYTIC SILENCER SIZING PROGRAM

CUSTOMER:	EXTERRAN		
PROJECT:	NUEVO		
DATE:	5/31/2013	QUOTATION I.D.:	RUNNING DUAL EXHAUST SYSTEMS
DESCRIPTION:	CAT 3612TALE, 1000RPM, 3550HP, 838 TEMP		
	OXIDATION REDUCTION		

PRESSURE DROP CALCULATED WITH A 20 INCH OUTLET

PERFORMANCE DATA INPUT AND CALCULATIONS

INPUT DATA			CALCULATED	
FLOW: ACFM @ 14.696 PSIA & TGAS°F			ACFM @ 14.696 PSIA & TGAS°F	11294.857
or ACFM @ PATM PSIA & TGAS°F			ACFM @ PATM PSIA & TGAS°F	11294.857
or SCFM 70/14.7			SCFM 70/14.7	4795.389
or NCuM/Min32/14.7			NCuM/Min32/14.7	126.054
or LB/MIN			LB/MIN	355.950
or LB/HR	21357		LB/HR	21357.000
S.G.			S.G.	0.991
or M.W.	28.7	* (SEE	M.W.	28.700
TGAS°F	788	NOTE)	TGAS°R	1248
PGAS PSIG			PGAS PSIA	14.696
PATM PSIA	14.696		OUTLET, SQ.FT.	2.182
OUTLET SIZE, IN	20		OUTLET VEL, FT/MIN	5177.2
FUEL, (GAS,or DIESEL)	GAS		VEL HEAD, IN H_2O	0.7033
SILENCER (201,202,205,211,216,218)	201		SCFH 32/14.7	264696 (FOR CAT CONV SPACE VEL CALC)
MAX. BODY CAPACITYor R **	5			
3-WAY OR OXIDATION	OXIDATION		USING CE-7140 ELEMENTS	
SIL. SERIES (2100,4100,5100-8100)	4100			
NUMBER OF ELEMENTS = ***	5			

* NOTE: 27.5 MW TYP FOR RICH BURN EXHAUST GAS; 28.7 MW TYP. FOR LEAN BURN GAS OR DIESEL

** MAX. BODY CAPACITY - For modular enter number of elements and half elements as 1, 2, 4, 6, etc.
For the small round (6",8",10",12",14",or 16") ENTER R IN C-30 AND THE DIAMETER SELECTED IN C-31.

*** NUMBER ELEMENTS For modular enter the number of full and half elements as 1, 1.5, 2, 2.5, 3, 3.5, …. up to entered Max. Body Capacity.
For small round (6",8",10",12",14",or 16") ENTER "1" AND ENTER THE DIAMETER OF IN C-31

CATALYST CONVERTER MODEL 201 V O - 5 - 500 - 4120

CALCULATED PRESSURE DROP = 3.91 INCHES H2O, CALCULATED SPACE VELOCITY = 78492

WITH LEAN BURN GAS ENGINE, MIN. OXIDATION RATE: 97 % CO, 95 % HCHO & 86 % NMNEHC

BASED ON STATED EXH. FLOW & TEMPERATURE	NOX	CO	HCHO	NMHC Note 1	NMNEHC Note 1
AND THE FOLLOWING EMISSIONS OUT OF ENGINE:	0.500	2.750	0.400	0.970	0.650
WE CALCULATE POST CONVERTER EMISSIONS NOT TO EXCEED:	0.500	0.083	0.020	0.485	0.091
UNITS:	gm/bhp-hr	gm/bhp-hr	gm/bhp-hr	gm/bhp-hr	gm/bhp-hr

Note 1: NMHC, NMNEHC & LESS THAN 50% Saturated; NMHC ASSUMED TO BE =<.33 THC & NMNEHC=<.2THC

Note 2: Oxidation Catalyst on Diesel or Lean Gas Cannot Reduce NOx

PERFORMANCE WARRANTY CONTINGENT UPON CONVERTER INSTALLATION ON A PROPERLY MAINTAINED ENGINE
EXCESSIVE OIL CONSUMPTION AND/OR FUEL CONSUMPTION MAY MASK OR POISON THE CATALYST AND REDUCE DESTRUCTION
ENGINE LUBE OIL MUST BE OF A TYPE RECOMMENDED FOR CATALYTIC CONVERTER SERVICE.
ELEMENT(S) WILL REQUIRE PERIODIC CLEANING. FREQUENCY WILL DEPEND ON LEVEL OF CONTAMINANTS IN THE EXHAUST GAS
CERTAIN CONTAMINANTS SUCH AS HEAVY METALS IN FUEL AND LUBE OIL WILL POSION THE CATALYST AND VOID THE WARANTY

Anguil Environmental Systems, Inc.
Regenerative Thermal Oxidizer

Date: May 15, 2013
Proposal #: AES-132691

Prepared for:

Dwight D. Settett
Nuevo Midstream, LLC
1331 Lamar, Suite 1450
Houston, TX 77010-3039

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"Our goal is to provide solutions today which help our customers remain profitable tomorrow"
– Gene Anguil / Founder and CEO

Committed to Cleaner Air.

Background:
- Founded in 1978
- Second generation family owned and operated
- Headquartered in Milwaukee, WI, USA with offices in Asia and Europe
- Over 1,650 oxidizers and countless heat recovery systems installed on six continents in a wide variety of industries

Company Size and Make-up:
- Annual sales in excess of $25 million
- In-house engineering staff consists of chemical, mechanical and electrical engineers
- Highly motivated employees who enjoy profit sharing and a rewarding work environment

What Makes Anguil Unique?
- Regulatory compliance is guaranteed
- Broad range of technology solutions that ensure an unbiased equipment selection
- Quality assurance program with complete factory acceptance testing prior to shipment
- An established safety program with continuous training for Anguil technicians
- Equipment is designed in Solidworks, ensuring accuracy and rapid completion

Products:

Air pollution control systems…
- Regenerative Thermal Oxidizers (RTO)
- Catalytic, Recuperative and Direct-Fired Thermal Oxidizers
- Concentrator systems
- Permanent Total Enclosures

…for VOC, HAP and odor abatement

Heat and energy recovery systems…
- Air-to-air heat exchangers
- Air-to-liquid heat exchangers
- Heat-to-power
- Energy Evaluations

…for improved efficiency and reduced operating costs

Aftermarket:

Service and Maintenance…
- 24/7 Emergency service response
- Operating cost reviews
- System upgrades and retrofits
- Spare parts and component packages
  - Preventive Maintenance Evaluations (PME)

… on any make or model, regardless of original manufacturer

Partial List of Satisfied Customers:

Boeing, Dow Chemical, Northrop Grumman, ExxonMobil, Johnson and Johnson, Peterbilt, Pfizer, Qualcomm, Rexam Beverage, Silgan Containers

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Executive Summary

1. Equipment Description

Nuevo Midstream, LLC has requested a proposal for an oxidizer for the destruction of VOCs from their Ramsey #3. The VOCs are in an inert CO_2 stream and will be combined with preheated fresh air, to prevent water and acid condensation, prior to being delivered to the new Regenerative Thermal Oxidizer. The RTO will be sized for a total flow of 25,000 SCFM.

The oxidizer design includes Anguil's approach to CO_2 dominated process streams with water vapor and hydrogen sulfide, which forms carbonic and sulfuric/sulfurous acid gases. Anguil proposes to preheat the inlet stream to the RTO above the acid and water dewpoint to prevent condensation of acids and water. The inlet preheat is achieved via Anguil's Fresh Air Preheat System.

2. Facility to be Controlled

Ramsey #3

3. Processes Controlled

Amine Vent

4. RTO Energy Recovery

95% Thermal Energy Recovery to minimize gas usage

5. Proposed Equipment

Model 250 (25,000 SCFM) Sour Gas Regenerative Thermal Oxidizers (RTO)

6. Anguil Benefits

* Seamless integration with the current process
* **True** 95% nominal heat transfer efficiency, adjusted for CO_2 content and altitude
* Fully automated PLC based controls
* Modem for remote diagnostics
* Field Tested and proven technology
* Full equipment warranty
* Factory test prior to shipment
* 24 hour service support

7. Results

* Anguil guarantees the conversion efficiency of 99% or an outlet concentration of 20 ppmv as C1 (methane), whichever is less stringent per EPA Method 25A.

Customer Process Specifications

- Process Information*:

Property	18 MMSCFD to RTO	20 MMSCFD to RTO
Temperature (°F) to Oxidizer	120	120
Volume Flow (MM SCFD) to Oxidizer	18.00	20.00
Compound	**mol%**	**mol%**
Nitrogen	0.00018	0.00018
Hydrogen Sulfide**	0.04521	0.04521
Carbon Dioxide	91.88499	91.88499
Methane	0.14099	0.14099
Ethane	0.04293	0.04293
Propane	0.01474	0.01474
i-Butane	0.00094	0.00094
n-Butane	0.00415	0.00415
i-Pentane	0.00041	0.00041
n-Pentane	0.00065	0.00065
Hexane	0.00045	0.00045
Water	7.86436	7.86436
Total Process Gas	**12,500 SCFM**	**13,889 SCFM**
Process Heat Release	**2.93 Btu/scf (18,082 Btu/lb)**	**2.93 Btu/scf (18,082 Btu/lb)**
Fresh air for Oxidation of VOCs	**372 SCFM**	**414 SCFM**
Fresh Air for 5% Stack O_2	**3,576 SCFM**	**3,973 SCFM**
Fresh Air for Temperature Control	**0 SCFM**	**0 SCFM**
Recirculated Oxidation Chamber Flow (5% O_2) for Inlet Preheat	**3,382 SCFM**	**3,758 SCFM**
Total Preheated Fresh Air Flow	**7,330 SCFM**	**8,145 SCFM**
Inlet Flow to Oxidizer	**19,830 SCFM**	**22,034 SCFM**
Maximum Allowable Process Heat Release	**18.00 Btu/scf (18,082 Btu/lb, 12,500 SCFM process)**	**16.00 Btu/scf (18,082 Btu/lb, 13,889 SCFM process)**
Preheated Fresh Air for Oxygen / Exotherm Control	**12,500 SCFM**	**11,111 SCFM**
Flow to Oxidizer	**25,000 SCFM**	
RTO System Design	**Model 250 RTO: 25,000 SCFM**	

* Assumed no halogenated or chlorinated compounds are present.
**Due to corrosion associated with the products of sulfur combustion (sulfurous/sulfuric acid), further materials of construction consideration may be required if the concentration of Hydrogen Sulfide is above 1 ppmv in the process stream

- Elevation: Assumed 3,000 FASL
- Facility Operating Schedule: 24 hr/day, 7 days/wk, 52 wk/yr
- Facility Power: 480 V / 60 Hz / 3 Ph
- Fuel Source: Natural Gas
- Performance Requirements: 99% VOC Destruction
- RTO location on Site: Outdoors

Note: Equipment has been designed and sized based on these customer parameters.

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Design Specifications

Size and Weight

- Maximum Flow (Includes Dilution Air): 25,000 SCFM
- Approximate Footprint: 43’ x 23’
- Approximate Weight: 120,000 lb
- Stack Height: 40’
- Stack Diameter: 54”
- Oxidizer Control Panel Location: Skid Mounted NEMA 3R Control Panel
- Suggest Foundation Size: 48’ x 28’

Utilities Required

- Fuel Requirements: 15-30 psig
- Electrical Power: 460V / 60 Hz / 3 Ph
- Required Compressed Air: 80-100 psig (-40°F dewpoint) 5-10 SCFM

Operation Information

- Oxidizer Guarantees: 99% VOC destruction efficiency or an outlet concentration of 20 ppmv as C1 (methane), whichever is less stringent per EPA Method 25A.
- Nominal Heat Transfer Efficiency: 95%
- System Fan Draft Design: Forced
- System Fan HP: 250 HP
- Combustion Fan HP: 10 HP
- Burner Installed Maximum Capacity: 8.0 MM BTU/hr
- Operating Set Point: 1550-1700°F

***Note: All weights, dimensions, horsepower ratings, burner sizing, and specific engineering details within the proposal are approximate and will be confirmed by Anguil Environmental following order placement.**

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Standard Equipment Specifications

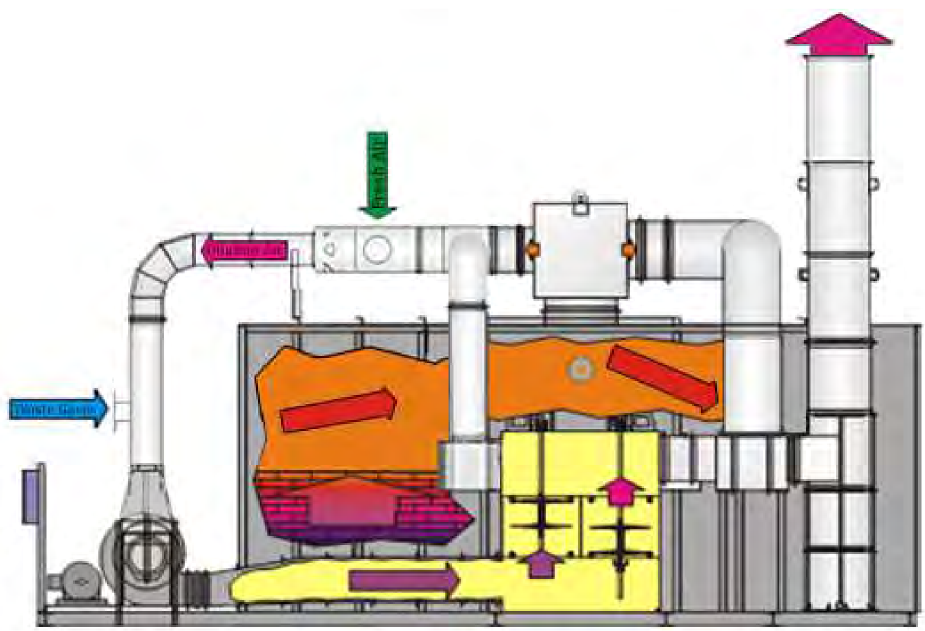
The Anguil Regenerative Thermal Oxidizer (RTO) destroys Hazardous Air Pollutants (HAPs), Volatile Organic Compounds (VOCs), and odorous emissions that are discharged from industrial processes. Emission destruction is achieved through the process of high temperature thermal or catalytic oxidation, converting the pollutants to carbon dioxide and water vapor while reusing the thermal energy generated to reduce operating costs.

During normal operation, fresh air required for oxidation is introduced and mixed with a combination of a slip stream off the combustion chamber as well as a slip stream from the exhaust stack. This heats the fresh air to an elevated temperature.

The VOC and HAP laden process gas enters the oxidizer through an inlet manifold and mixes with the heated fresh air to obtain a design preheat temperature. This ensures all water entrained in the process gas remains entrained and any un-insulated metal surfaces of the oxidizer remain above acid dew points resulting from the oxidation of sulfur bearing compounds.

The gases then enter the oxidizer through an inlet manifold to flow control poppet valves that direct the gases into energy recovery chambers. Here, the process gases and contaminants are progressively heated in the ceramic media beds as they move toward the combustion chamber. In the combustion chamber, the gases reach oxidation temperature and remain at this temperature for a duration that allows proper destruction.

Once oxidized in the combustion chamber, the hot purified air releases its thermal energy as it passes through the outlet media bed. The outlet bed is heated and the gas is cooled so that the outlet gas temperature is only slightly higher than the inlet temperature. Poppet valves alternate the airflow direction into the media beds to maximize energy recovery within the oxidizer. The high energy recovery within these oxidizers reduces the auxiliary fuel requirement and saves operating cost. The Anguil oxidizer achieves high destruction efficiency and self-sustaining operation with no auxiliary fuel usage at process gas concentrations as low as 5-8 Btu/scf.



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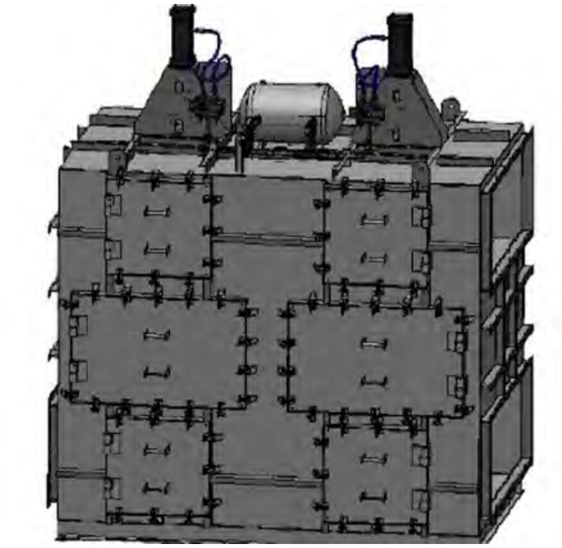
POPPET VALVES

Anguil's poppet valves are uniquely designed to divert high volume process air into and out of the oxidizer, properly balance VOC loading, maintain destruction efficiency and optimize heat recovery. We custom design, manufacture and install these vital components to ensure reliability and trouble free operation. Anguil has several poppet assemblies that have been operating continuously since 1993 and have required nothing but regular maintenance.

SPECIFICATIONS



- **316L Stainless Steel Shaft, Disk & Seat**
- Poppet Box Body: **316L Stainless Steel**
- Cylinder Actuator Supports: 1/4" Plate Steel
- Parker Hannifin Heavy Duty Pneumatic Cylinder:
  90 psi, 10 CFM, -40℉
- Heavy Duty, High Flow, 4-way Parker Hannifin Solenoid Valve
- Bolted Actuator Mountings with Shaft Guarding
- Connecting Duct Work to Fan and Exhaust Stack
- Compressed air Accumulator Tank Included
- End of Stroke Switches
- Solenoid Valve Exhaust Flow Control
- *External insulation of the poppet valves for personnel protection and to prevent condensation has not been included at this time. Anguil recommends that it will be the most cost effective to insulate onsite during installation.*

FEATURES

- Vertical Shaft
- Double Acting, Three-way Air Flow Design:
- Reliable Metal to Metal Seal:
  1MM+ cycles
- Removable Machined Seats:
  <0.25% leakage at 18" W.C.
- Valve Pressure Drop: Maximum of 2" W.C.
- Rectangular Ports for Inlet/Outlet Ducting
- Removable Actuator Mounting
- Hinged Access Doors with Toggle clips
- Lockout Device with Padlock Provision
- Quiet Operation
- Over Temperature Protection
- Short valve switch distance

ADVANTAGES

Energy Efficient – Compressed air consumption to switch solenoids from closed to open position is minimal
Dependable – Two-disc system minimizes valve switch distance and wear
Ease of Maintenance – Multiple hinged access doors make occasional cleaning and bearing maintenance easy

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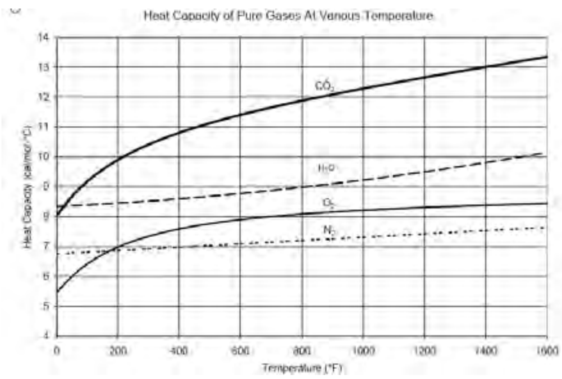
HEAT TRANSFER MEDIA

- Two (2) beds of high temperature chemical porcelain structured heat transfer media
- **Media has been adjusted to account for the high CO_2 content to provide a true 95% thermal efficiency. The heat capacity of CO_2 is higher than that of air (~70% nitrogen) meaning you need more energy to heat up the CO_2. More media would be required to provide more preheat to the incoming CO_2.**
- Ceramic media designed to provide optimum heat transfer surface area
- Media bed for proper air distribution and optimum RTO performance
- Low system pressure drop



BURNER(S)/FUEL TRAIN

The burner installed capacity is higher than required during normal operation. This allows the system to respond rapidly to significant airflow increases, preventing loss of proper RTO operation temperatures. The burner capacity is also sufficient to maintain system operating temperature during full airflow, VOC free conditions.

- Maxon Kinemax low NOx burner
- Fuel Train fabricated to FM Global specifications
- Service platform and ladder
- 3" burner view port
- Fireye flame safety control with self-checking dynamic UV scanner
- **Carbon steel fuel train – excludes all aluminum, brass or cast iron**
- **Maxon shut-off valves with steel bodies in lieu of ASCO valve with aluminum bodies**
- **Fisher (or equivalent) natural gas regulator with steel body in lieu of Eclipse regulator with aluminum body**
- **Flow-Tek (or equivalent) natural gas control valve with steel body in lieu of Eclipse control valve with cast iron body**
    - **Upgrade includes a higher class of valve**

COMBUSTION AIR FAN

- Twin City Fan, New York Blower or equal
- Pre-piped and pre-wired
- TEFC motor
- Inlet filter
- Independent controlled fuel and combustion air valves
- **Bray (or equivalent) combustion air control valve with steel body in lieu of Eclipse control valve with cast iron body**
    - **Upgrade includes a higher class of valve**

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FRESH AIR PREHEAT SYSTEM

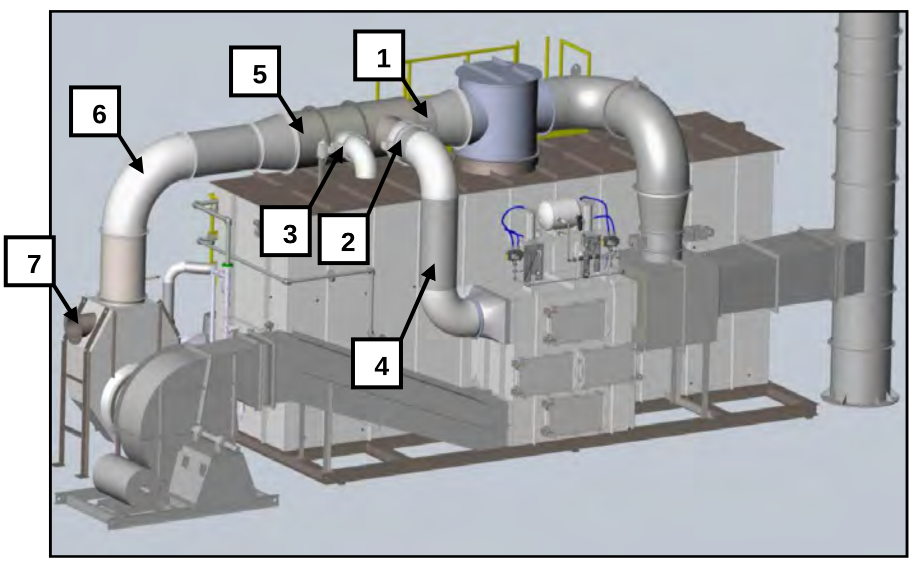
Fresh air is used during oxidizer start-up/shut-down, purging during idle time, and to provide oxygen for oxidation. Anguil recommends that during normal operation, the fresh air be preheated above the sulfuric acid dew point prior to mixing with the process gas upstream of the system fan to prevent water condensation and to ensure all parts in contact with the process stream are above the acid dew point.

Anguil's design incorporates a fresh air preheat system that utilizes heat from the combustion chamber to heat fresh air. Three dampers are employed to achieve the desired preheat temperature. The fresh air damper allows fresh air into the system and is controlled by an oxygen analyzer in the RTO exhaust stack.

The recycle damper controls the amount of heat taken from the combustion chamber. It provides the main input of heat required to achieve the required desired preheat temperature.

All damper positions are controlled by a signal from the PLC with an actuator and positioner. **The recommended RTO inlet preheat temperature with the given amount of H_2S in the process stream is 50°F above the expected sulfuric acid dew point temperature (340°F).**

- Recycle damper internally lined with hard refractory
  - Sized based on a maximum combustion chamber temperature of 1800°F
  - 330 Stainless Steel shaft and blade
  - Step seat in the refractory
- Stack recycle and fresh air dampers mechanically linked with a single actuator
- Static Mixer constructed out of 304 Stainless Steel
- *External insulation of the recirculation ductwork for personnel protection and to prevent acid/water condensation has not been included at this time. Anguil recommends that it will be the most cost effective to insulate onsite during installation.*



1. Recycle Damper
2. Exhaust Stack Recycle Damper
3. Fresh Air Damper
4. Exhaust Stack Recycle Duct
5. Static Mixer
6. Preheat Duct
7. Process Inlet

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RTO SYSTEM FAN

- System Fan sized for -1 in. W.C. at the process inlet
- Twin City Fan, New York Blower or equal
- VFD rated motor
- Flexible connection on inlet/outlet of fan
- *External insulation of the system fan for personnel protection and to prevent condensation has not been included at this time. Anguil recommends that it will be the most cost effective to insulate onsite during installation.*

SYSTEM CONTROLS

The system controls are located in a **heated and air conditioned NEMA 3R control panel enclosure mounted on the RTO skid.** In the event of a system shutdown, the touch screen will indicate the cause of the shutdown via a digital message in English.

- **NEMA 3R main control panel enclosure to be mounted on the oxidizer skid**
- Allen Bradley CompactLogix family PLC (Programmable Logic Controller) controls
- **Allen Bradley Panelview 1000** display
- Digital chart recorder: monitors combustion chamber and system outlet temperatures
- Ethernet modem for remote diagnostics and service support

VARIABLE FREQUENCY DRIVE (VFD)

The **Allen Bradley PowerFlex** variable frequency drive regulates the airflow through the system. It is controlled by a flow transmitter located in the recirculation duct. The VFD is mounted with the system controls in the control panel enclosure. It aids in minimizing operating cost by providing system fan turn-down during periods of low airflow.

  - Mounted in an Anguil supplied **heated and air conditioned NEMA 3R panel enclosure**

ENERGY RECOVERY CHAMBERS

The RTO's energy recovery chambers are rectangular cross-sections constructed of **vinyl ester coated carbon steel**. They are reinforced to withstand the pressure requirement of the process air fan and all other applied loads. A **316L stainless steel** support structure is also provided to support the oxidizer chambers, media support grid and the ceramic heat recovery media itself. In order to allow for routine inspection of the heat recovery media, cold face and media support grid, hinged access door(s) complete with gaskets are included.

- Two (2) carbon steel energy recovery chambers
  - Internally insulated: 6" thick, 8# density ceramic module insulation
  - Insulation rated for 2300°F
  - Insulation modules: shop installed with 310 stainless steel reinforcements and mounting hardware
  - **Internally coated with a vinyl ester coating to protect against sulfuric acid corrosion**
- Support Structure – **316L stainless steel**
- Media support grid – **316L stainless steel**
- Hinged access door(s) with gaskets

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COMBUSTION CHAMBER

The combustion chamber is a rectangular cross-section constructed of **vinyl ester coated carbon steel** and reinforced to withstand the pressure requirements of the process air fan and all other applied loads. The inverted "U" shape design provides the retention time to obtain the specified VOC destruction efficiency. In order to allow for routine inspection of the heat recovery media, insulation and burner, hinged access door(s) complete with gaskets are included.

- Inverted "U" shaped oxidation chamber
    - Internally insulated: 8" thick, 8# density ceramic module insulation
    - Insulation rated for 2300°F
    - Insulation modules: shop installed with 310 stainless steel reinforcements and mounting hardware
    - **Internally coated with a vinyl ester coating to protect against sulfuric acid corrosion**
- Hinged access door(s) with gaskets

EXHAUST STACK

- Constructed of **316L stainless steel**
- **Free-standing exhaust stack with access ladder and platform**
- Two (2) EPA tests ports provided at 90^o, to each other
- Stack is sandblasted, zinc primed and high temperature coating applied
- **An oxygen analyzer will be supplied in the RTO exhaust stack to control the dilution air and ensure a minimum of 5% oxygen content in the RTO exhaust gas**

BAKE OUT

The oxidizer can be operated off-line from the process in a bake-out mode to allow for the removal of organic build-up on the cold face of the heat exchange media. At a reduced airflow, the outlet temperature is allowed to reach an elevated temperature before the flow direction is switched. This hot air vaporizes organic particulate that may have collected on the cold face of the heat exchange media. The flow direction is then switched and the opposite cold face is cleaned. The area below the media support grid will be insulated to prevent the temperature of the outer skin from increasing during bake-out.

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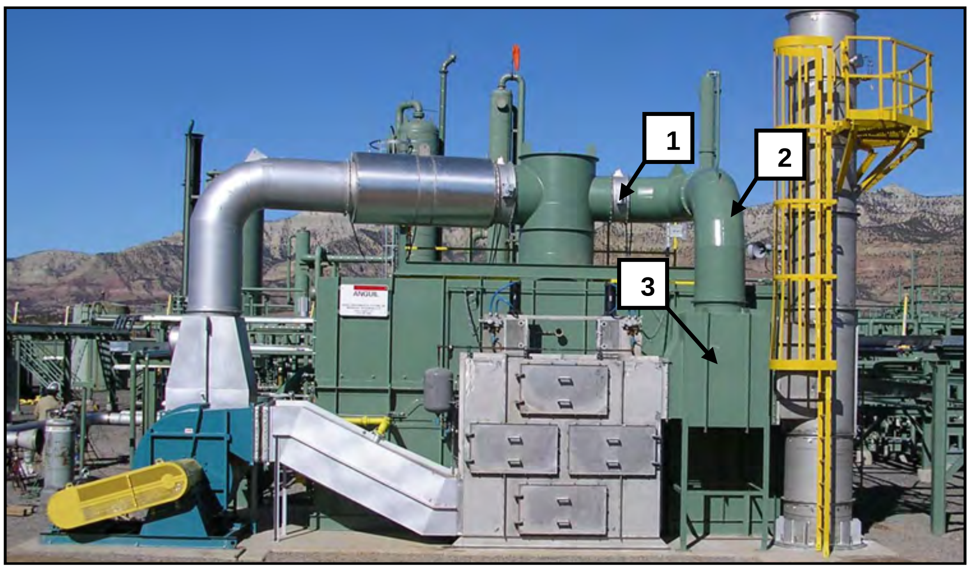
HOT SIDE BYPASS

At higher VOC loadings, an RTO unit can experience a high temperature shutdown if the RTO has no means of removing the additional energy from VOC oxidation. The hot side bypass, during periods of high solvent loading, provides a means of removing energy from the RTO combustion chamber. It diverts combustion chamber flow to the RTO exhaust, reducing the amount of heat that gets stored in the outlet media bed. When the flow direction switches, there is less heat stored in the new inlet bed, which prevents the combustion chamber temperature from exceeding the high temperature limit.

- 330 stainless steel shaft and blade
- Hot Bypass Damper internally lined with hard refractory
- Damper position controlled by PLC and driven with pneumatic actuator with positioner
- Refractory-lined bypass duct to mixing plenum on grade provides necessary residence time to achieve required destruction efficiency
- Duct and valve sized based on maximum temperature of 1800℉
- **Duct will be manufactured out of carbon steel and internally coated with a vinyl ester coating to protect against sulfuric acid corrosion.**



1. Refractory Lined Hot Side Bypass Damper
2. Refractory Lined Hot Side Bypass Duct
3. Mixing Plenum

PAINTING

All exposed surfaces of the oxidizer shall be primed coated with a high solids epoxy coating. The finish coat shall be a gloss high solids polyurethane multi-function weather resistant coating. The natural gas and compressed air piping will be primed and painted with one (1) coat of Anguil's standard coating. All other equipment will be the manufacturer's standard paint and color. Prior to painting, all welds will be caulked.

- UV resistant polyurethane paint
- Paint color can be specified by the customer

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OPERATION & MAINTENANCE MANUALS

- Two (2) hard copy sets of the Operation and Maintenance Manuals (O&M) containing the sequence of operation and drawings
- CD-ROM of all Vendor Bulletins

FINAL ASSEMBLY AND SHOP TEST

We pre-assemble and pre-test modular components in our factory to provide significant savings of time and money during installation and start-up. Units are prewired and pre-piped at the factory for improved quality control and trouble-free start-up.

- Temporary assembly of system
- Inspection of the unit for manufacturing quality
- Check fuel and electrical connections
- Starting of burner and fuel train
- Warning labels are installed
- Test ports are installed
- Run electrical rigid conduit
- Fans and motors installed, cleared of debris and checked for quality
- Valves to be cycled and set
- Customer is invited to witness shop testing

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Items Not Included

- Concrete pad / platform
- Dumpster
- Interconnecting wiring between process equipment / isolation valve
- RTO Isolation Valve
- All natural gas piping to RTO fuel train
- All compressed air piping to RTO air train (-40F dewpoint requirement)
- Winterization of the pneumatic piping and sensing lines
- Insulation and cladding for condensation and personnel protection
- Exhaust stack ladder and platform (free standing stack required)
- Power source to RTO control panel
- Piping/valves from process to oxidizer inlet
- Oxidizer system fan and combustion air fan disconnects not included
- Personnel protection, security fencing and lighting
- Moving of oxidizer obstructions, fencing, landscaping, etc.
- Multiple installation trips if delays beyond Anguil's control
- All roof and building penetrations
- All fire suppression piping and controls
- All required sound abatement equipment
- Compliance testing
- Phone line to modem
- Taxes, permits
- Overtime, holiday or weekend work
- Mechanical and electrical installation (Can be quoted as an option)
- Budget Freight (Can be quoted as an option)

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Pricing and Delivery

One (1) Anguil Model 250 Sour Gas Regenerative Thermal Oxidizer will process up to 25,000 SCFM of VOC laden process gas, with the required fresh air for oxygen and temperature control, providing 99% destruction efficiency.

EQUIPMENT PRICE F.O.B. (Origin), Freight Prepaid & Add to the invoice	**$897,700.00**
STARTUP AND TRAINING	$1,160/day plus travel and living
PACKAGING AND FREIGHT	Billed at Cost plus 10% handling fee

SHIPMENT: 18-22 weeks after approval of drawings (GA and P&ID)

****Due to the rapidly changing market price of metals, Anguil reserves the right to adjust the final price of the equipment accordingly to account for market price.**

TERMS:
30% down payment due upon order placement
30% due 8 weeks after receipt of purchase order, net 30
30% due prior to shipment or notification of readiness to ship
10% due upon start-up, not to exceed 60 days from shipment, net 30

ALL PRICES HAVE BEEN QUOTED IN US DOLLARS
ALL PRICES WILL REMAIN FIRM FOR 60 DAYS;
THEREAFTER, A RE-QUOTE MAY BE REQUIRED

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Estimated Fuel Usage

The following compares the fuel usage between an RTO and a vapor combustor at varying process flows:

FUEL USAGE COMPARISON						
Still Vent Rate (MMSCFD)	Vapor Combustor Fuel Usage (Btu/hr)	Vapor Combustor Fuel Cost ($/hr)	RTO Fuel Usage (Btu/hr)	RTO Fuel Cost ($/hr)	RTO Fuel Savings ($/hr)	RTO Fuel Savings ($/yr)
18.00	40,820,000	$163.28	4,124,000	$16.50	$146.78	$1,285,827.84
20.00	45,360,000	$181.44	4,546,000	$18.18	$163.26	$1,430,122.56

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Field Service Rates 2013

Field Service Engineer and Installation Supervision

Straight Time (weekdays, 8 hours/day; min. of 8 hours)	$1,160/day
Overtime (more than 8 hours/day and Saturdays)	$180/hour
Sundays and Holidays	$200/hour
Emergency Service Rate (site visit within 48 hours of call)	$180/hour
Controls Field Service Engineer	$190/hour
Travel Time	$95/hour
Trip Preparation	$100/visit
Report Writing	$100/visit
International Labor Rate	$1,275/day
Technical Phone Support	$100/hour

Project Engineer

Principal Engineer (weekdays, 8 hours/day; min. of 8 hours)	$1,355/day
Project Engineer (weekdays, 8 hours/day; min. of 8 hours)	$1,125/day
Electrical Engineer / Programming	$150/hour

Travel and Living Expenses

Airline ticket	Cost + 15% Administrative fee
Hotel	Cost + 15% Administrative fee
Car rental	Cost + 15% Administrative fee
Meal allowance	$41/day
Meal allowance – International	$62/day
Airport parking	$15/day
Extra Luggage (tools, etc.), roundtrip	$100/trip
Mileage	$0.80/mile

Start-Up and Training Services	**$1,160/day plus travel and living exp.**
International Start-Up and Training Services	**$1,245/day plus travel and living exp.**

Equipment will be checked mechanically and electrically and all operational data will be verified

- Service technician will be provided to start-up and balance the oxidizer
- Operator training conducted during start-up. Training includes classroom sessions and on unit training.

Terms
Net 30 days
Terms subject to change upon credit review

2013 Holiday Schedule (premium rates apply)
New Years Day
Good Friday
Memorial Day
Independence Day
Labor Day
Thanksgiving (2 days)
Christmas (3 days)
New Years

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Standard Terms and Conditions

1. General

Anguil's prices are based on these terms and conditions of sale. These terms and conditions may not be modified unless prior written agreement is reached between both Anguil and Purchaser and signed by an authorized representative of Anguil.

2. Warranty

Any contract resulting from this proposal will require start-up assistance to validate our warranty. This will requires a technical service representative to be present at the time of initial start-up and must give release of operation of the equipment in accordance with the Seller's operating and maintenance manual.

Anguil Environmental Systems, Inc. (ANGUIL) warrants to the buyer that the products delivered will (a) be free from defects in material and manufacturing workmanship (b) conform to manufacturer's applicable product descriptions attached to Seller's quotation. If no product descriptions or specifications are attached to the quotation, manufacturer's specification in effect on the date of shipment will apply.

The product warranties are for a period of 12 months from the date of start-up, if start-up is within thirty (30) days of shipment or 15 months from date of shipment, whichever shall occur first. The product warranties will apply provided the following conditions:

- The equipment is operated and maintained as described in the Anguil operating manual provided with the equipment
- Recommended routine maintenance must be performed and documented per Anguil instructions at recommended intervals.
- This warranty does not apply to heat damage that may occur due to improper use of the RTO, or due to fires that may occur due to excessive buildup of organic matter in the process ductwork.

Warranty Exclusions

Warranty coverage does not include: (a) freight, labor, travel, and living expenses associated with parts replacement, (b) normal maintenance items such as fan belts, fuses, light bulbs, spark igniters, bearings, seals, gasket, lubrication and cleaning of the equipment, (c) abrasion, corrosion or negligence in operating the equipment on the part of Buyer or Buyer's subcontractor(s).

In the event the customer, or any installation contractor employed by the customer, contracts outside ANGUIL for installation work or erection of quoted equipment, the customer will assume full responsibility for workmanship resulting from said contract.

3. Performance Guarantee

Anguil guarantees the conversion efficiency as stated in the proposal or an outlet concentration of 20 ppmv as C1 (methane), whichever is less stringent.

- The test methods to be used to show compliance is US EPA Method 25A
- Anguil requires seven (7) days notice of the official testing to meet DRE guarantee. Anguil reserves the right to review of the test protocol prior to official testing to and to have personnel present at the official compliance test.
- Equipment is operating in accordance with Seller's written operating and maintenance instructions.
- Anguil shall rely on process and chemical information provided by Purchaser or its agents and not be liable for undisclosed or unknown process or chemical materials.

4. Prices / Taxes

Prices are quoted in U.S. dollars and may be accepted only within 60 days from date of quotation by Anguil. Anguil reserves the right to adjust the final price of the equipment according to the market price of metals. Any sales, use or other taxes and duties imposed on this sale are not included in the quoted price. If this order is placed from one of the following states; AZ, CA, GA, MA, MI, NJ, NY, WI; and is taxable, sales tax can be added and will be billed separately to the Purchaser. Anguil will accept a valid exemption certificate from the Purchaser for those orders not taxable. If this order is placed from a state not listed, the Purchaser must provide one of the following; 1) Tax exempt certificate; 2) Pollution control exclusion certificate or 3) Self assessment letter to Anguil.

5. Cancellations
Orders canceled by Purchaser must be in writing and will be subject to a cancellation fee on the following basis: On any orders canceled prior to the procurement of material and the commencement of fabrication the Purchaser will be subject to a cancellation fee of 15% of Contract value to cover costs incurred for Engineering services plus overhead and reasonable expenses including rep commission made or incurred by Anguil in the initial processing of the order. On orders cancelled after the initiation of production, payment shall be made on the basis of actual cost of labor, materials, components (cancellation fees if applicable) and work in progress plus overhead expenses. Upon written receipt of cancellation, Anguil will immediately stop all work except that necessary to effect termination.

6. Engineering Submittals
Anguil will provide layout drawings to the Purchaser for approval and the Purchaser will be asked to comment on these drawings in regards to scope of work, dimensions, site interferences or specifications agreed upon at the time of sale. Approval of Purchaser does not relieve Anguil of obligations to perform to all other specifications of the contract. Final layout drawings will be used to prepare the fabrication drawings after they are returned with the Purchaser's approval.

Anguil will provide Process and Instrumentation Diagrams (P&ID) for approval and the Purchaser will be asked to comment on these drawings in regards to process verification, scope of supply, system features and instrumentation. Approval of Purchaser does not relieve Anguil of obligations to perform to all other specifications of the contract. Final P&ID drawings will be used to prepare the electrical schematics and controls after they are returned with the Purchaser's approval.

All additional Engineering and or drafting costs associated with revising the layout drawings or P&ID as a result of changes requested by Purchaser after initial approval will be considered a Change Order and quoted to the Purchaser at Anguil's prevailing per hour rates. If any such changes cause an increase in the cost or time required for performance, a Change Order will be submitted for Purchase approval. Upon receipt of written approval, Anguil will be granted the authority to proceed with agreed upon changes.

7. Shipping Schedules
Anguil will use its best efforts to meet delivery dates agreed to pursuant to the order of which these terms are a part. Anguil shall not be liable for any delay in delivery when such a delay is, directly or indirectly, caused by fires, floods, terrorism, accidents, riots, government interference, strikes, shortage of labor, materials or supplies, delays in transportation or any other causes beyond the reasonable control of Anguil. In the event of delay in performance due to any such cause, the date of delivery or time for completion will be adjusted to reflect the length of time lost by reason of such delay.

If a delay in shipping is requested less than 6 weeks prior to shipment, Anguil will complete the system and invoice any "prior to shipment" payment milestone which will be due at the time of the original scheduled ship date. Upon completion of the system, Anguil at its option may place the equipment in storage facilities and the Purchaser will pay the cost of storage, special handling fees and insurance. Equipment held for the Purchaser shall be at the risk of the Purchaser.

8. Acceptance and Testing of Equipment
Purchaser will upon delivery inspect and test the equipment and notify Anguil in writing within 30 days of installation or 90 days of shipment, whichever comes first, of all defects discovered including failure of the equipment to meet quoted performance standards. Failure to give such notice constitutes an irrevocable acceptance of the equipment and the equipment will be deemed to conform with the terms of this Agreement, and Purchaser will be bound to pay for the equipment. Upon notification of a defect as above provided, Anguil will repair the equipment and correct the system's performance.

9. Risk of Loss
Quotations are F.O.B., place of shipment, unless otherwise noted. The risk of loss of the equipment shipped will pass to Purchaser upon Anguil's delivery of the equipment to a carrier. Claims for damage in shipment must be filed by Purchaser with the carrier.

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10. Limitation of Liability
In no event will Anguil, its subcontractors, or representatives be held responsible, or liable for any claim, whether in warranty, contract, tort or strict liability for any special, indirect, incidental or consequential damages resulting from the purchase of equipment (including but not limited to incidental or consequential damages for labor, lost profits, lost sales, injury to person or to property or any other incidental loss or damages).

Purchaser agrees that Purchaser's exclusive remedy and Anguil's sole liability on any such claim will be limited to reimbursement from Anguil of the purchase price actually received by Anguil from Purchaser for the equipment in question.

Anguil shall rely on process and chemical information provided by Purchaser or its agents and not be liable for undisclosed or unknown process or chemical materials (Please refer to Customer Process Specifications section in the proposal).

11. Security Interest
Purchaser grants Anguil a security interest in the equipment to secure payment of the balance due hereunder. Purchaser authorizes Anguil to file this Agreement as a Financing Statement or to sign on behalf of Purchaser and file any other Financing Statements with respect to the equipment in any place Anguil deems necessary.

12. Attorney's Fees
Purchaser will be liable for all reasonable expenses and attorney's fees incurred by Anguil in enforcing its rights and remedies under this Agreement.

13. Ordinances
Any and all required licenses, certificates and operating permits will be the sole responsibility of the Buyer unless otherwise specified by Anguil.

14. Miscellaneous
The terms and conditions contained herein and any other terms and conditions stated in Anguil's proposal or specifications attached hereto will constitute the entire agreement between Anguil and Purchaser. The terms and conditions stated herein are applicable to all orders accepted by Anguil unless otherwise specifically agreed to by Anguil in writing. Purchaser will be deemed to have assented to all such terms if any part of the described equipment is accepted. If Purchaser finds any terms not acceptable, Purchaser must so notify Anguil within 15 days. Any additional or different terms contained in Purchaser's order to response hereto will be deemed objected to by Anguil and will be of no effect. This proposal and its acceptance will be governed in all respects by the laws of Wisconsin. In the event of a breach, both parties agree that any suit will be brought in the jurisdiction of the Courts of Wisconsin.

ORDER ACCEPTED BY:

ANGUIL ENVIRONMENTAL SYSTEMS, INC.		BUYER:	
BY:	______________________	BY:	______________________
PRINT:	______________________	PRINT:	______________________
TITLE:	______________________	TITLE:	______________________
DATE:	______________________	DATE:	______________________

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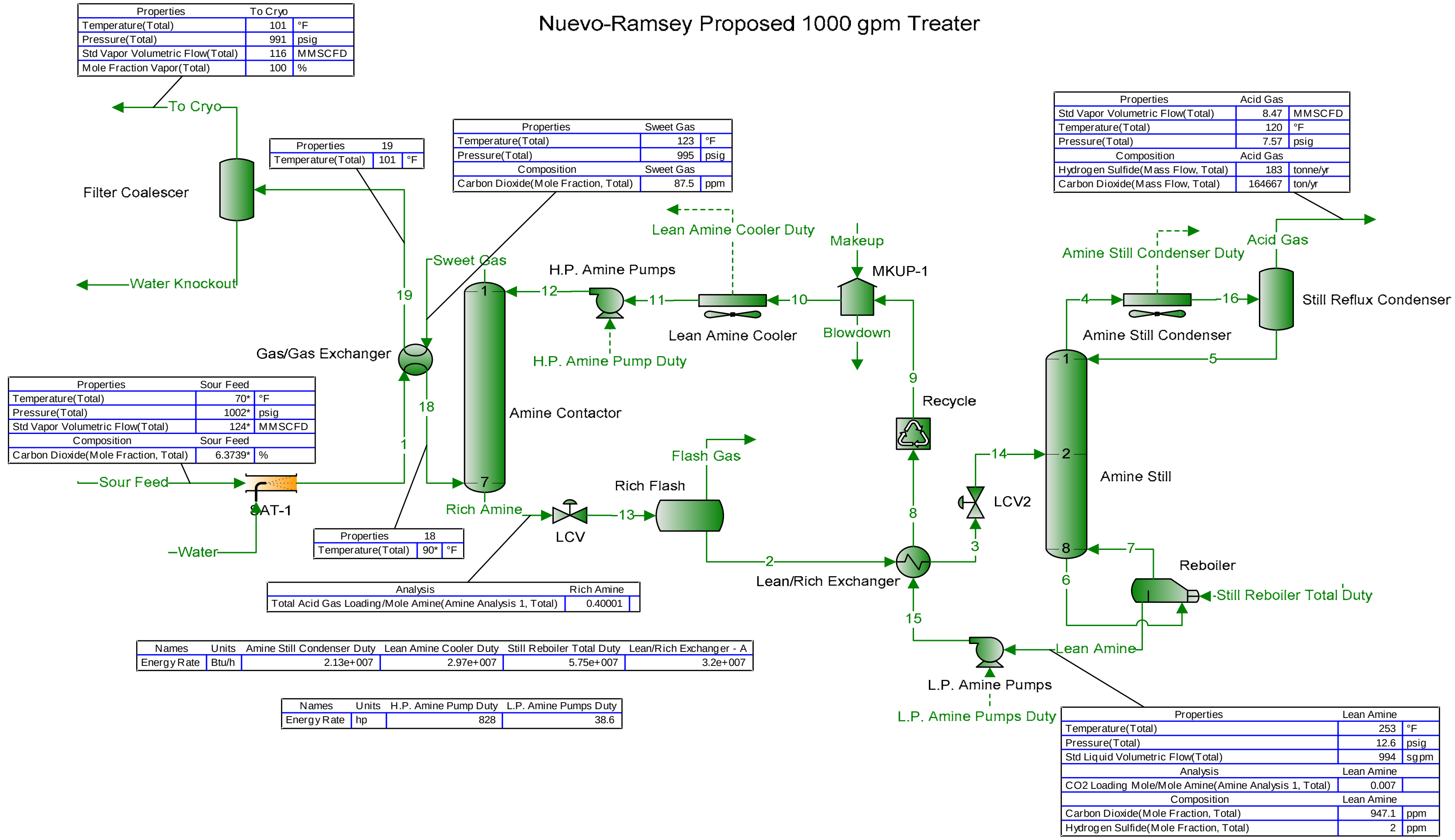
Nuevo-Ramsey Proposed 1000 gpm Treater



Properties	To Cryo	
Temperature(Total)	101	°F
Pressure(Total)	991	psig
Std Vapor Volumetric Flow(Total)	116	MMSCFD
Mole Fraction Vapor(Total)	100	%

Properties	19	
Temperature(Total)	101	°F

Properties	Sweet Gas	
Temperature(Total)	123	°F
Pressure(Total)	995	psig
Composition	Sweet Gas	
Carbon Dioxide(Mole Fraction, Total)	87.5	ppm

Properties	Acid Gas	
Std Vapor Volumetric Flow(Total)	8.47	MMSCFD
Temperature(Total)	120	°F
Pressure(Total)	7.57	psig
Composition	Acid Gas	
Hydrogen Sulfide(Mass Flow, Total)	183	tonne/yr
Carbon Dioxide(Mass Flow, Total)	164667	ton/yr

Properties	Sour Feed	
Temperature(Total)	70*	°F
Pressure(Total)	1002*	psig
Std Vapor Volumetric Flow(Total)	124*	MMSCFD
Composition	Sour Feed	
Carbon Dioxide(Mole Fraction, Total)	6.3739*	%

Properties	18	
Temperature(Total)	90*	°F

Analysis	Rich Amine	
Total Acid Gas Loading/Mole Amine(Amine Analysis 1, Total)	0.40001	

Names	Units	Amine Still Condenser Duty	Lean Amine Cooler Duty	Still Reboiler Total Duty	Lean/Rich Exchanger - A
Energy Rate	Btu/h	2.13e+007	2.97e+007	5.75e+007	3.2e+007

Names	Units	H.P. Amine Pump Duty	L.P. Amine Pumps Duty
Energy Rate	hp	828	38.6

Properties	Lean Amine	
Temperature(Total)	253	°F
Pressure(Total)	12.6	psig
Std Liquid Volumetric Flow(Total)	994	sgpm
Analysis	Lean Amine	
CO2 Loading Mole/Mole Amine(Amine Analysis 1, Total)	0.007	
Composition	Lean Amine	
Carbon Dioxide(Mole Fraction, Total)	947.1	ppm
Hydrogen Sulfide(Mole Fraction, Total)	2	ppm

Office of Air and Radiation **October 2010**

AVAILABLE AND EMERGING TECHNOLOGIES FOR REDUCING GREENHOUSE GAS EMISSIONS FROM THE PETROLEUM REFINING INDUSTRY

Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry

Prepared by the

Sector Policies and Programs Division
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

October 2010

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1.0 Introduction

This document is one of several white papers that summarize readily available information on control techniques and measures to mitigate greenhouse gas (GHG) emissions from specific industrial sectors. These white papers are solely intended to provide basic information on GHG control technologies and reduction measures in order to assist States and local air pollution control agencies, tribal authorities, and regulated entities in implementing technologies or measures to reduce GHGs under the Clean Air Act, particularly in permitting under the prevention of significant deterioration (PSD) program and the assessment of best available control technology (BACT). These white papers do not set policy, standards or otherwise establish any binding requirements; such requirements are contained in the applicable EPA regulations and approved state implementation plans.

This document provides information on control techniques and measures that are available to mitigate greenhouse gas (GHG) emissions from the petroleum refining industry at this time. Because the primary GHG emitted by the petroleum refining industry are carbon dioxide (CO_2) and methane (CH_4), the control technologies and measures presented here focus on these pollutants. While a large number of available technologies are discussed here, this paper does not necessarily represent all potentially available technologies or measures that that may be considered for any given source for the purposes of reducing its GHG emissions. For example, controls that are applied to other industrial source categories with exhaust streams similar to the petroleum refining industry may be available through "technology transfer" or new technologies may be developed for use in this sector.

The information presented in this document does not represent U.S. EPA endorsement of any particular control strategy. As such, it should not be construed as EPA approval of a particular control technology or measure, or of the emissions reductions that could be achieved by a particular unit or source under review.

2.0 Petroleum Refining

2.1 Overview of Petroleum Refining Industry

Petroleum refineries produce liquefied petroleum gases (LPG), motor gasoline, jet fuels, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen), and other products through distillation of crude oil or through redistillation, cracking, or reforming of unfinished petroleum derivatives. There are three basic types of refineries: topping refineries, hydroskimming refineries, and upgrading refineries (also referred to as "conversion" or "complex" refineries). Topping refineries have a crude distillation column and produce naphtha and other intermediate products, but not gasoline. There are only a few topping refineries in the U.S., predominately in Alaska. Hydroskimming refineries have mild conversion units such as hydrotreating units and/or reforming units to produce finished gasoline products, but they do not upgrade heavier components of the crude oil that exit near the bottom of the crude distillation column. Some topping/hydroskimming refineries specialize in processing heavy crude oils to produce asphalt. There are eight operating asphalt plants and approximately 20 other hydroskimming refineries operating in the United States as of January 2006 (Energy Information Administration [EIA], 2006). The vast majority (approximately 75 to 80 percent) of the approximately 150 domestic refineries are upgrading/conversion refineries. Upgrading/conversion refineries have cracking or coking operations to convert long-chain, high molecular weight hydrocarbons ("heavy distillates") into smaller hydrocarbons that can be used to produce gasoline product ("light distillates") and other higher value products and petrochemical feedstocks.

Figure 1 provides a simplified flow diagram of a typical refinery. The flow of intermediates between the processes will vary by refinery, and depends on the structure of the refinery, type of crude processes, as well as product mix. The first process unit in nearly all refineries is the crude oil or "atmospheric" distillation unit (CDU). Different conversion processes are available using thermal or catalytic processes, *e.g.*, delayed coking, catalytic cracking, or catalytic reforming, to produce the desired mix of products from the crude oil. The products may be treated to upgrade the product quality (*e.g.*, sulfur removal using a hydrotreater). Side processes that are used to condition inputs or produce hydrogen or by-products include crude conditioning (*e.g.*, desalting), hydrogen production, power and steam production, and asphalt production. Lubricants and other specialized products may be produced at special locations. More detailed descriptions of petroleum refining processes are available in other locations (U.S. EPA, 1995, 1998; U.S. Department of Energy [DOE], 2007).

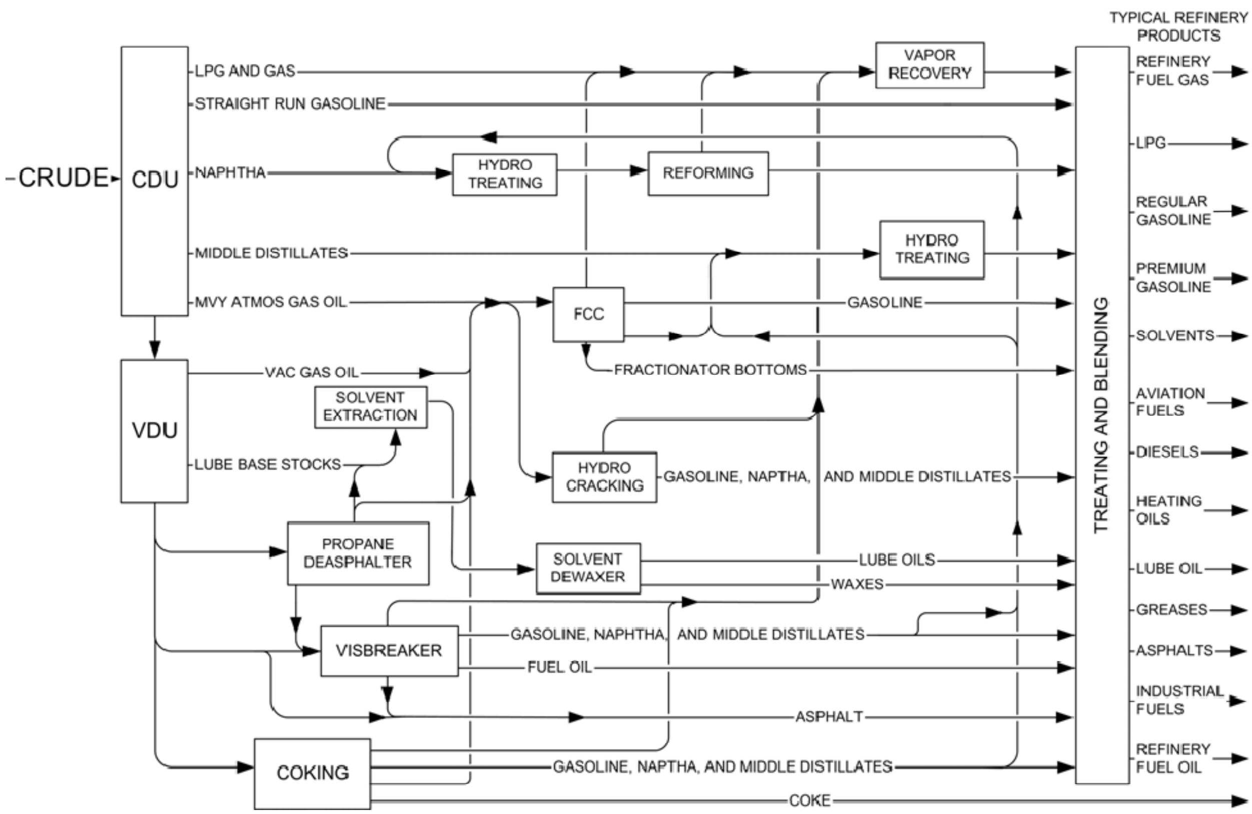

Figure 1. Simplified flowchart of refining processes and product flows. Adapted from Gary and Handwerk (1994).

2.2 Petroleum Refining GHG Emission Sources

The petroleum refining industry is the nation's second-highest industrial consumer of energy (U.S. DOE, 2007). Nearly all of the energy consumed is fossil fuel for combustion; therefore, the petroleum refining industry is a significant source of GHG emissions. In addition to the combustion-related sources (*e.g.*, process heaters and boilers), there are certain processes, such as fluid catalytic cracking units (FCCU), hydrogen production units, and sulfur recovery plants, which have significant process emissions of CO_2. Methane emissions from a typical petroleum refinery arise from process equipment leaks, crude oil storage tanks, asphalt blowing, delayed coking units, and blow down systems. Asphalt blowing and flaring of waste gas also contributes to the overall CO_2 and CH_4 emissions at the refinery. Based on a bottom-up, refinery-specific analysis (adapted from Coburn, 2007, and U.S. EPA, 2008), GHG emissions from petroleum refineries were estimated to be 214-million metric tons of CO_2 equivalents (CO_2e), based on production rates in 2005. **Figure 2** provides a breakdown of the nationwide emissions projected for different parts of the petroleum refineries based on this bottom-up analysis.

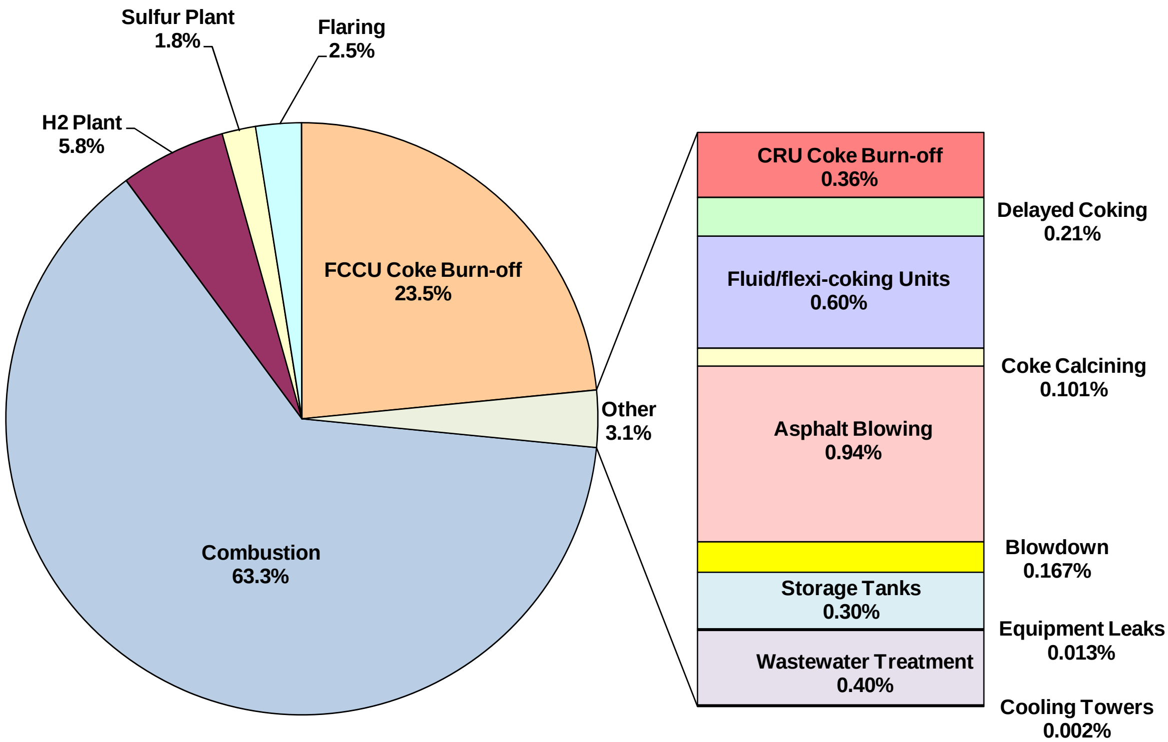

Figure 2. Contribution of different emission sources to the nationwide CO_2 equivalent GHG emissions from petroleum refineries.

Figure 3 presents what GHG are emitted by refineries. CO_2 is the predominant GHG emitted by petroleum refineries, accounting for almost 98 percent of all GHG emissions at petroleum refineries. Methane emissions are 4.7-million metric tons CO_2e and account for 2.25 percent of the petroleum refinery emissions nationwide. Note that the relative magnitude of CO_2 and CH_4 emissions is dependent on the types of process units and other characteristics of the refinery. Facilities that do not have catalytic cracking units and hydrogen plants will tend to have a higher fraction of their total GHG emissions released as CH_4.

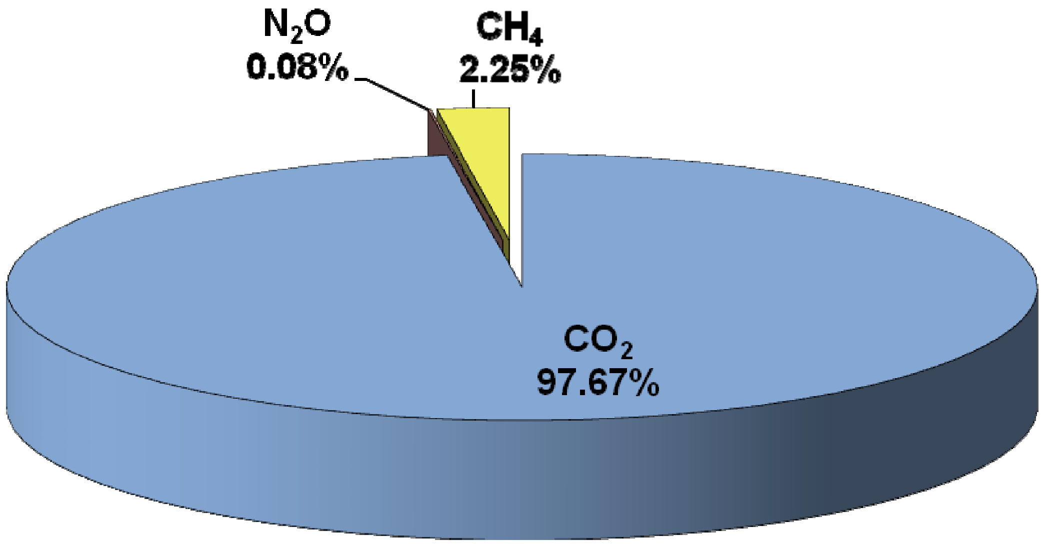

Figure 3. GHG emissions from petroleum refineries.

The petroleum refining industry is one of the largest energy consuming industries in the United States. Thus, a primary option to reduce CO_2 emissions is to improve energy efficiency. In 2001, the domestic petroleum refining industry consumed an estimated 3,369 trillion British Thermal Units (TBtu). One report estimated the CO_2 emissions from this energy consumption to be about 222 million tonnes, which accounts for about 11.6 percent of industrial CO_2 emissions in the United States (Worrell and Galitsky, 2005). The EIA provides on-site fuel consumption data as well as electricity and steam purchases (EIA, 2009). These data were used to estimate the CO_2 emissions resulting from this fuel consumption using the emission factors from the Intergovernmental Panel on Climate Change (IPCC) (2006), and converted to appropriate units (Coburn, 2007). **Figure 4** presents the projected CO_2 emissions from the direct, on-site fuel consumption, as well as the indirect, off-site electricity and steam purchases. From Coburn (2007), the on-site annual CO_2 emissions from fuel combustion were 190 million tonnes in 2005 and the overall CO_2 emissions from energy consumption (including purchased steam and electricity) were 216 million tonnes in 2005, which agrees well with the estimate of Worrell (2005). As seen in Figure 4, catalyst coke consumption dropped 10 percent from 2006 to 2008. Much of the resulting CO_2 emission reductions were offset by increased electricity and steam purchases. As nearly all catalytic cracking units recover the latent heat from the catalyst coke burn-off exhaust to produce steam and/or electricity, the decrease in catalyst coke consumption does not translate into an equivalent net GHG emissions reduction when indirect CO_2 emissions from electricity and steam purchases are considered.

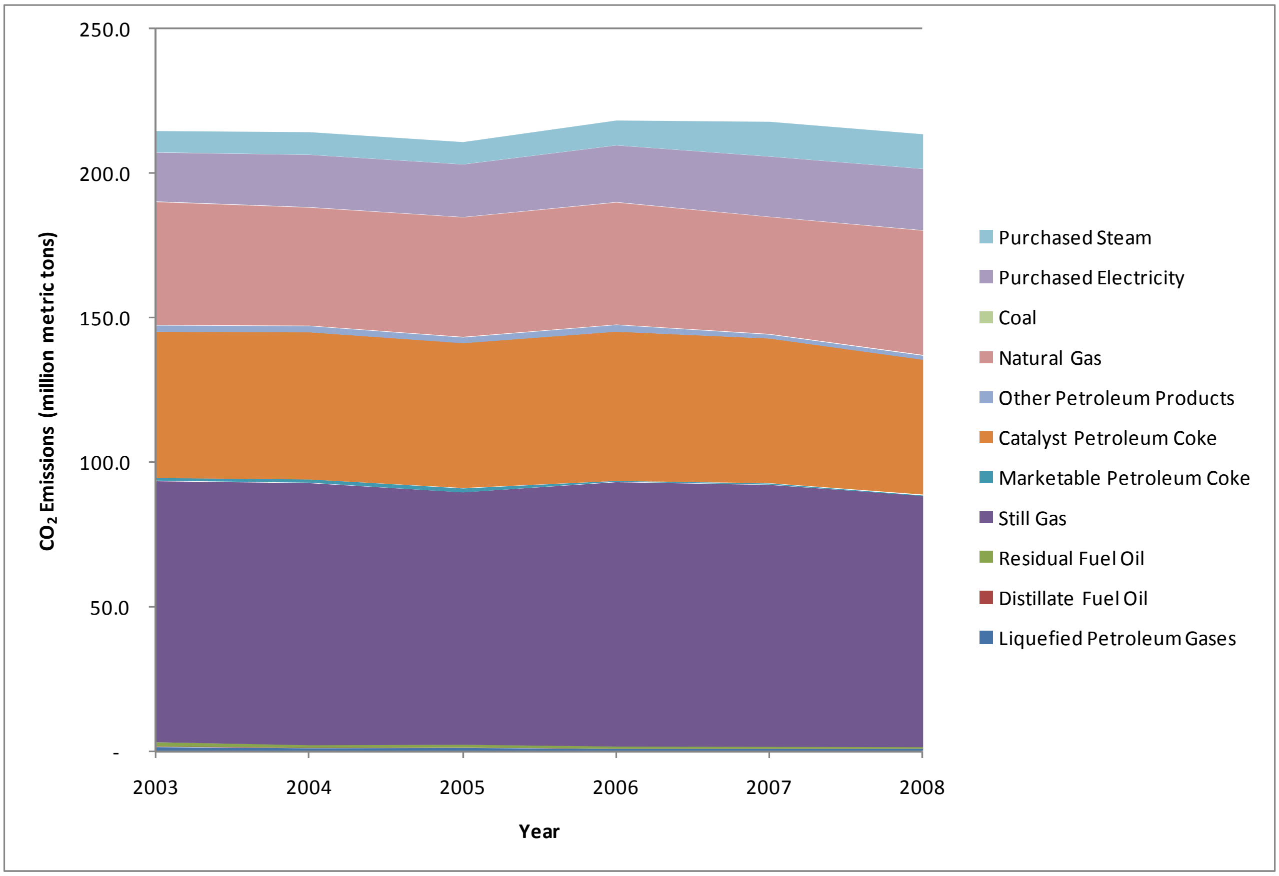

Figure 4. Direct CO_2 emissions from fuel consumption and indirect CO_2 emissions from electricity and steam purchases at U.S. petroleum refineries from 2003 to 2008.

The remainder of this section provides brief descriptions of the process units and other sources that generate significant GHG emissions at a petroleum refinery.

2.2.1 Stationary Combustion Sources

Stationary combustion sources are the largest sources of GHG emissions at a petroleum refinery. Combustion sources primarily emit CO_2, but they also emit small amounts of CH_4 and nitrous oxide (N_2O). Stationary combustion sources at a petroleum refinery include process heaters, boilers, combustion turbines, and similar devices. For this document, flares are considered a distinct emission source separate from other stationary combustion sources. Nearly all refinery process units use process heaters. Typically, the largest process heaters at a petroleum refinery are associated with the crude oil atmospheric and vacuum distillation units and the catalytic reforming unit (if present at the refinery).

In addition to direct process heat, many refinery processes also have steam and electricity requirements. Some refineries purchase steam to meet their process's steam requirements; others use dedicated on-site boilers to meet their steam needs. Similarly, some refineries purchase electricity from the grid to run their pumps and other electrical equipment; other refineries have co-generation facilities to meet their electricity needs and may produce excess electricity to sell to the grid. Refineries that produce their own steam or electricity will have higher on-site fuel usage, all other factors being equal, than refineries that purchase these utilities. A boiler for producing plant steam can be the largest source of GHG emissions at the refinery, particularly at refineries that do not have catalytic cracking units.

The predominant fuel used at petroleum refineries is refinery fuel gas (RFG), which is also known as still gas. RFG is a mixture of light C1 to C4 hydrocarbons, hydrogen, hydrogen sulfide (H_2S), and other gases that exit the top (overhead) of the distillation column and remain uncondensed as they pass through the overhead condenser. RFG produced at different locations within the refinery is typically compressed, treated to remove H_2S (if necessary), and routed to a central location (*i.e.*, mix drum) to supply fuel to the various process heaters at the refinery. This RFG collection and distribution system is referred to as the fuel gas system. A refinery may have several fuel gas systems, depending on the configuration of the refinery, supplying fuel to different process heaters and boilers.

The fuel gas generated at the refinery is typically augmented with natural gas to supply the full energy needs of the refinery. Depending on the types of crude oil processed and the process units in operation, the amount of supplemental natural gas needed can change significantly. Consequently, there may be significant variability in the fuel gas composition between different refineries and even within a refinery as certain units are taken off-line for maintenance.

2.2.2 Flares

Flares are commonly used in refineries as safety devices to receive gases during periods of process upsets, equipment malfunctions, and unit start-up and shutdowns. Some flares receive only low flows of "purge" or "sweep" gas to prevent air (oxygen) from entering the flare header and possibly the fuel gas system while maintaining the readiness of the flare in the event of a significant malfunction or process upset. Some flares may receive excess process gas on a frequent or routine basis. Some flares may be used solely as control devices for regulatory purposes. Combustion of gas in a flare results in emissions of predominately CO_2, along with small amounts of CH_4 and N_2O.

2.2.3 Catalytic Cracking Units

In the catalytic cracking process, heat and pressure are used with a catalyst to break large hydrocarbons into smaller molecules. The FCCU is the most common type of catalytic cracking unit currently in use. The FCCU feed is pre-heated to between 500 and 800 degrees Fahrenheit (ºF) and contacted with fine catalyst particles from the regenerator section, which are at about 1,300 ºF in the feed line ("riser"). The feed vapor, which is heavy distillate oil from the crude or vacuum distillation column, reacts when contacted with the hot catalyst to break (or crack) the large hydrocarbon compounds into a variety of lighter hydrocarbons. During this cracking process, coke is deposited on the catalyst particles, which deactivates the catalyst. The catalyst separates from the reacted ("cracked") vapors in the reactor; the vapors continue to a fractionation tower and the catalyst is recycled to the regenerator portion of the FCCU to burn-off the coke deposits and prepare the catalyst for reuse in the FCCU riser/reactor (U.S. EPA, 1998).

The FCCU catalyst regenerator generates GHG through the combustion of coke (essentially solid carbon with small amounts of hydrogen and various impurities) that was deposited on the catalyst particles during the cracking process. CO_2 is the primary GHG emitted; small quantities of CH_4 and N_2O are also emitted during "coke burn-off." An FCCU catalyst regenerator can be designed for complete or partial combustion. A complete-combustion FCCU operates with sufficient air to convert most of the carbon to CO_2 rather than carbon monoxide (CO). A partial-combustion FCCU generates CO as well as CO_2, so most partial-combustion FCCU are typically followed by a CO boiler to convert the CO to CO_2. Most refineries that operate an FCCU recover useful heat generated from the combustion of catalyst coke during catalyst regeneration; the heat recovered from catalyst coke combustion offsets some of the refinery's ancillary energy needs. The FCCU catalyst regeneration or coke burn-off vent is often the largest single source of GHG emissions at a refinery.

Thermal catalytic cracking units (TCCU) are similar to FCCU, except that the catalyst particles are much bigger and the system uses a moving bed reactor rather than a fluidized system. The generation of GHG, however, is the same. Specifically, GHG are generated in the regenerator section of the TCCU when coke deposited on the catalyst particles is burned-off in order to restore catalyst activity.

2.2.4 Coking Units

Coking is another cracking process, usually used at a refinery to generate transportation fuels, such as gasoline and diesel, from lower-value fuel oils. A desired by-product of the coking reaction is petroleum coke, which can be used as a fuel for power plants as well as a raw material for carbon and graphite products. Coking units are often installed at existing refineries to increase the refinery's ability to process heavier crude oils. There are three basic types of coking units: delayed coking units, (traditional) fluid coking units, and flexicoking units. Delayed coking units are the most common, and all new coking units are expected to be delayed cokers.

Delayed Coking Units. Delayed coking is a semibatch process using two coke drums and a single fractionator tower (distillation column) and coking furnace. A feed stream of heavy residues is introduced to the fractionating tower. The bottoms from the fractionator are heated to about 900 to 1,000 °F in the coking furnace, and then fed to an insulated coke drum where thermal cracking produces lighter (cracked) reaction products and coke. The reaction products produced in the coke drum are fed back to the fractionator for product separation. After the coke drum becomes filled with coke, the feed is alternated to the parallel (empty) coke drum, and the filled coke drum is purged and cooled, first by steam injection, and then by water addition. A coke drum blowdown system recovers hydrocarbon and steam vapors generated during the quenching and steaming process. Once cooled, the coke drum is vented to the atmosphere, opened, and then high pressure water jets are used to cut the coke from the drum. After the coke cutting cycle, the drum is closed and preheated to prepare the vessel for going back on-line (i.e., receiving heated feed). A typical coking cycle will last for 16 to 24 hours on-line and 16 to 24 hours cooling and decoking. The primary GHG released from a delayed coking unit is CH_4, which is emitted both from the blowdown system (if not controlled) and from the atmospheric venting and opening of the coke drum.

Fluid Coking Units. The fluid coking process is continuous and occurs in a reactor rather than a coke drum like the delayed coking process. Fluid coking units produce a higher grade of petroleum coke than delayed coking units; however, unlike delayed coking units that use large process preheaters, fluid coking units burn 15 to 25 percent of the coke produced to provide the heat needed for the coking reactions (U.S. DOE, 2007). The coke is burned with limited air, so large quantities of CO are produced (similar to a partial combustion FCCU), which are subsequently burned in a CO boiler. Like the FCCU, the combustion of the petroleum coke and subsequent combustion of CO generates large quantities of CO_2 along with small amounts of CH_4 and N_2O. For the few refineries with fluid coking units, the fluid coking units are significant contributors to the refinery's GHG emissions. Fluid coking units are not significant contributors to the nationwide emissions totals because there are only three fluid coking units in the United States; however, fluid coking units have emissions comparable to (and slightly greater than) catalytic cracking units of the same throughput capacity.

Flexicoking Units. The flexicoking process is very similar to the fluid coking unit except that a coke gasifier is added that burns nearly all of the produced coke at 1700 – 1800 °F with steam to produce low heating value synthesis gas (syngas). The produced syngas, along with entrained fines, is routed through the heater vessel for fluidization of the hot coke bed and for heat transfer to the solids. The syngas is then treated to remove entrained particles and reduced sulfur compounds and the syngas can then be used in specially designed boilers or other combustion sources that can accommodate the low heat content of the syngas. Most of the CO_2 emissions produced in the flexicoking unit will not be released at the unit, but rather it will be part of the syngas. Some of the CO_2 produced in the flexicoking unit is expected to be removed as part of the sulfur removal process and subsequently released in the sulfur recovery plant; the CO_2 that remains in the scrubbed syngas will be released from the stationary combustion unit that uses the syngas as fuel (usually a boiler specifically designed to use the low heating value content syngas). Therefore, while the flexicoking unit is not expected to have significant GHG emissions directly from the unit, the flexicoking unit will impact the energy balance and GHG emissions from other sources at the refinery.

2.2.5 Catalytic Reforming Units

In the catalytic reforming unit (CRU), low-octane hydrocarbon distillates, generally gasoline and naphtha are reacted with a catalyst to produce aromatic compounds such as benzene. An important by-product of the reforming reaction is hydrogen. The feed to the CRU must be treated to remove sulfur, nitrogen, and metallic contaminants, typically using a catalytic hydrotreater (which will consume some hydrogen, but not as much as produced in the CRU). The CRU usually has a series of three or four reactors. The reforming reactor is endothermic, so the feed must be heated prior to each reactor vessel. Coke deposits slowly on the catalyst particles during the processing reaction, and this "catalyst coke" must be burned-off to reactivate the catalyst, generating CO_2, along with small amounts of CH_4 and N_2O.

There are three types of CRU based on how the regeneration of the catalyst is performed: continuous CRU, cyclic CRU, and semi-regenerative CRU. In a continuous CRU (or platformers), small quantities of the catalyst are continuously removed from a moving bed reactor system, purged, and transported to a continuously operated regeneration system. The regenerated catalyst is then recycled to the moving bed reactor. Continuous reformers generally operate at lower pressures than other reforming units, resulting in higher coke deposition rates. Cyclic CRU has an extra reactor vessel, so that one reactor vessel can be isolated from the unit for regeneration. After the first vessel is regenerated, it is brought back on-line and the second reactor vessel is then isolated and regenerated and so on until all vessels have been regenerated. Thus, in cyclic units, the CRU continues to operate and individual reactor vessels are regenerated in a cyclical process many times during a single year. In a semi-regenerative CRU, the entire reforming unit is taken off-line to regenerate the catalyst in the reactor vessels. Catalyst regeneration in a semi-regenerative CRU typically occurs once every 12 to 24 months (18 months is typical) and lasts approximately 1 to 2 weeks (U.S. EPA, 1998).

In addition to the CO_2 generated during coke burn-off, there may be some CH_4 emissions during the depressurization and purging of the reactor vessels of recycled catalyst prior to regeneration. While the CH_4 emissions from the depressurization and purging processes are expected to be negligible in most cases, natural gas (*i.e.*, CH_4) is occasionally used as the purge gas, in which case the CH_4 emissions would not be negligible.

2.2.6 Sulfur Recovery Vents

Hydrogen sulfide (H_2S) is removed from the refinery fuel gas system through the use of amine scrubbers. While the selectivity of H_2S removal is dependent on the type of amine solution used, these scrubbers also tend to extract CO_2 from the fuel gas. The concentrated sour gas is then processed in a sulfur recovery plant to convert the H_2S into elemental sulfur or sulfuric acid. CO_2 in the sour gas will pass through the sulfur recovery plant and be released in the final sulfur plant vent. Additionally, small amounts of hydrocarbons may also be present in the sour gas stream. These hydrocarbons will eventually be converted to CO_2 in the sulfur recovery plant or via tail gas incineration. The most common type of sulfur recovery plant is the Claus unit, which produces elemental sulfur. The first step in a Claus unit is a burner to convert one-third of the sour gas into sulfur dioxide (SO_2) prior to the Claus catalytic reactors. GHG emissions from the fuel fired to the Claus burner are expected to be accounted for as a combustion source. After that, the sulfur dioxide and unburned H_2S are reacted in the presence of a bauxite catalyst to produce elemental sulfur. Based on process-specific data collected in the development of emission standards for petroleum refineries, there are 195 sulfur recovery trains in the petroleum refining industry (U.S. EPA, 1998).

2.2.7 Hydrogen Plants

The most common method of producing hydrogen at a refinery is the steam methane reforming (SMR) process. Methane, other light hydrocarbons, and steam are reacted via a nickel catalyst to produce hydrogen and CO. Excess CH_4 is added and combusted to provide the heat needed by this endothermic reaction. The CO generated by the initial reaction further reacts with the steam to generate hydrogen and CO_2 (U.S. DOE, 2007). According to EIA's Refinery Capacity Report 2006 (EIA, 2006), 54 of the 150 petroleum refineries have hydrogen production capacity. CO_2 produced as a byproduct of SMR hydrogen production accounts for approximately 6 percent of GHG emissions from petroleum refineries nationwide, but can account for 25 percent of the GHG emissions from an individual refinery. Many of the hydrogen plants located at a petroleum refinery are operated by third-parties. It is unclear if the hydrogen production units reported by EIA include all hydrogen plants co-located at a refinery or only those that are directly owned and operated by the refinery.

2.2.8 Asphalt Blowing Stills

Asphalt or bitumen blowing is used for polymerizing and stabilizing asphalt to improve its weathering characteristics in the production of asphalt roofing products and certain road asphalts. Asphalt blowing involves the oxidation of asphalt flux by bubbling air through liquid asphalt flux at 260 °Celsius (C) (500 °F) for 1 to 10 hours depending on the desired characteristics of the product. The vessel used for asphalt blowing is referred to as a "blowing still." The emissions from a blowing still are primarily organic particulate with a fairly high concentration of gaseous hydrocarbon and polycyclic organic matter as well as reduced sulfur compounds. The blowing still gas also contains significant quantities of CH_4 and CO_2. The blowing still gas is commonly controlled with a wet scrubber to remove sour gas, entrained oil, particulates, and condensable organics and/or a thermal oxidizer to combust the hydrocarbons and sour gas to CO_2 and SO_2.

2.2.9 Storage Tanks

Storage tanks will generally have negligible GHG emissions except when unstabilized crude oil is stored or a methane blanket is used in the storage tank. Unstabilized crude oil is crude oil that has not been stored at atmospheric conditions for prolonged periods of time (several days to a week) prior to being received at the refinery. Most crude oil deposits also include natural gas (*i.e.*, CH_4); some of the CH_4 is dissolved in the crude oil at the pressure of the crude oil deposit. When crude oil is extracted, it is often stored temporarily at atmospheric conditions to either discharge or recover the dissolved gases. If the crude oil is transported under pressure (*e.g.*, via a pipeline) either immediately or shortly after extraction, the dissolved gases will remain in the crude oil until it reaches the refinery. The dissolved gases will be subsequently released from this "unstabilized" crude oil when the crude oil is stored at atmospheric conditions at a storage tank at the refinery.

2.2.10 Coke Calcining Units

Coke calcining units are a significant source of CO_2 emissions; however, only a few petroleum refineries have on-site coke calcining units. Coke calciners are used to burn-off sulfur, volatiles, and other impurities in the coke to produce a premium grade coke that can be used to make electrodes, anode vessels, and other products. A small fraction of the coke is consumed/pyrolyzed in the process under oxygen starved conditions; the process gas generated is then combusted in an afterburner by mixing the process gas with air in the presence of a flame. Most of the CO_2 generated from the process/afterburner system is attributable to the volatile content of the coke fed to the calciner.

2.2.11 Other Ancillary Sources

Refineries may also contain other ancillary sources of GHG emissions. Most refineries have wastewater treatment systems and some refineries have landfills. While the aerobic biodegradation of wastes is generally considered to be biogenic, anaerobic degradation of waste producing CH_4 emission is not. The high organic loads and stagnant conditions in an oil-water separator are conducive to anaerobic degradation, and the oil water separator may be a fairly significant ancillary source of CH_4 emissions. Landfills are also conducive to anaerobic degradation. Depending on the organic content of the waste material managed in a landfill, the landfill may also be a fairly significant ancillary source of CH_4 emissions.

The refinery's fuel gas system will generally contain significant concentrations of CH_4; certain process units may either generate methane or use methane and other light ends as part of the process operations (*e.g.*, SMR hydrogen production). Leaking equipment components (*e.g.*, valves, pumps, and flanges) may, therefore, be a source of CH_4 emissions. Leak detection and repair (LDAR) programs are commonly used to identify and reduce emissions from equipment components; however, most LDAR programs exclude the fuel gas system. Similar to equipment leaks, some heat exchangers may develop leaks whereby gases being cooled can leak into the cooling water. Although these leaks are not direct releases to the atmosphere, light hydrocarbons that leak into the cooling water will generally be released to the atmosphere in cooling towers (for recirculated cooling water systems) or ponds/receiving waters (in once through systems). As several heat exchangers at a refinery cool gases that contain appreciable quantities of CH_4 (e.g., a distillation column's overhead condenser), cooling towers may also be a source of CH_4 emissions. Nonetheless, CH_4 emissions from equipment leaks, either directly to the atmosphere from leaking equipment components or indirectly from cooling towers from leaking heat exchangers, are generally expected to have a minimal contribution to a typical refinery's total GHG emissions.

3.0 Summary of GHG Reduction Measures

Table 1 summarized the GHG reduction measures described in this document. Additional detail regarding these GHG reduction measures are provided in Section 4, Energy Programs and Management Systems, and Section 5, GHG Reduction Measures by Source, of this document.

Table 1. Summary of GHG Reduction Measures for the Petroleum Refining Industry

GHG Control Measure	Description	Efficiency Improvement/ GHG emission reduction	Retrofit Capital Costs ($/unit of CO_2e)	Payback time (years)	Demon-strated in Practice?	Other Factors
Energy Efficiency Programs and Systems						
Energy Efficiency Initiatives and Improvements	Benchmark GHG performance and implement energy management systems to improve energy efficiency, such as: ▪ improve process monitoring and control systems ▪ use high efficiency motors ▪ use variable speed drives ▪ optimize compressed air systems ▪ implement lighting system efficiency improvements	4-17% of electricity consumption		1-2 years	Yes	

GHG Control Measure	Description	Efficiency Improvement/ GHG emission reduction	Retrofit Capital Costs ($/unit of CO_2e)	Payback time (years)	Demon-strated in Practice?	Other Factors
Stationary Combustion Sources						
Steam Generating Boilers (see also ICI Boiler GHG BACT Document)						
Systems Approach to Steam Generation	Analyze steam needs and energy recovery options, including: ▪ minimize steam generation at excess pressure or volume ▪ use turbo or steam expanders when excesses are unavoidable ▪ schedule boilers based on efficiency				Yes	
Boiler Feed Water Preparation	Replace a hot lime water softener with a reverse osmosis membrane treatment system to remove hardness and reduce alkalinity of boiler feed.	70-90% reduction in blowdown steam loss; up to 10% reduction in GHG emissions		2-5 years	Yes	
Improved Process Control	Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture and limit excess air.	1-3% of boiler emissions		6 - 18 months	Yes	Low excess air levels may increase CO emissions.
Improved Insulation	Insulation (or improved insulation) of boilers and distribution pipes.	3-13% of boiler emissions		6 - 18 months	Yes	
Improved Maintenance	All boilers should be maintained according to a maintenance program. In particular, the burners and condensate return system should be properly adjusted and worn components replaced. Additionally, fouling on the fireside of the boiler and scaling on the waterside should be controlled.	1-10% of boiler emissions			Yes	
Recover Heat from Process Flue Gas	Flue gases throughout the refinery may have sufficient heat content to make it economical to recover the heat. Typically, this is accomplished using an economizer to preheat the boiler feed water.	2-4% of boiler emissions		2 years	Yes	
Recover Steam from Blowdown	Install a steam recover system to recover blowdown steam for low pressure steam needs (e.g., space heating and feed water preheating).	1 –3%		1 - 3 years	Yes	

GHG Control Measure	Description	Efficiency Improvement/ GHG emission reduction	Retrofit Capital Costs ($/unit of CO_2e)	Payback time (years)	Demon-strated in Practice?	Other Factors
Reduce Standby Losses	Reduce or eliminate steam production at standby by modifying the burner, combustion air supply, and boiler feedwater supply, and using automatic control systems to reduce the time needed to reach full boiler capacity.	Up to 85% reduction in standby losses (but likely a small fraction of facility total boiler emissions)		1.5 years	Yes	
Improve and Maintain Steam Traps	Implement a maintenance plan that includes regular inspection and maintenance of steam traps to prevent steam lost through malfunctioning steam traps.	1-10% of boiler emissions			Yes	
Install Steam Condensate Return Lines	Reuse of the steam condensate reduces the amount of feed water needed and reduces the amount of energy needed to produce steam since the condensate is preheated.	1- 10% of steam energy use		1-2 years	Yes	
Process Heaters						
Combustion Air Controls-Limitations on Excess air	Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture and limit excess air.	1-3%		6-18 months	Yes	
Heat Recovery: Air Preheater	Air preheater package consists of a compact air-to-air heat exchanger installed at grade level through which the hot stack gases from the convective section exchange heat with the incoming combustion air. If the original heater is natural draft, a retrofit requires conversion to mechanical draft.	10-15% over units with no preheat.			Yes	**May increase NOx emissions**
Combined Heat and Power						
Combined Heat and Power	Use internally generated fuels or natural gas for power (electricity) production using a gas turbine and generate steam from waste heat of combustion exhaust to achieve greater energy efficiencies			5 years	Yes	
Carbon Capture						
Oxy-combustion	Use pure oxygen in large combustion sources to reduce flue gas volumes and increase CO_2 concentrations to improve capture efficiency and costs				No	

GHG Control Measure	Description	Efficiency Improvement/ GHG emission reduction	Retrofit Capital Costs ($/unit of CO_2e)	Payback time (years)	Demon-strated in Practice?	Other Factors
Post-combustion Solvent Capture	Use solvent scrubbing, typically using monoethanolamine (MEA) as the solvent, for separation of CO_2 in post-combustion exhaust streams				Yes	
Post-combustion membranes	Use membrane technology to separate or adsorb CO2 in an exhaust stream		$55-63		No	
Fuel Gas System and Flares						
Fuel Gas System						
Compressor Selection	Use dry seal rather than wet seal compressors; use rod packing for reciprocating compressors				Yes	
Leak Detection and Repair	Use organic vapor analyzer or optical sensing technologies to identify leaks in natural gas lines, fuel gas lines, and other lines with high methane concentrations and repair the leaks as soon as possible.	80-90% of leak emissions; <0.1% refinery-wide			Yes	
Sulfur Scrubbing System	Evaluate different sulfur scrubbing technologies or solvents for energy efficiency				Yes	
Flares						
Flare Gas Recovery	Install flare gas recovery compressor system to recover flare gas to the fuel gas system			1 yr	Yes	
Proper Flare Operation	Maintain combustion efficiency of flare by controlling heating content of flare gas and steam- or air-assist rates				Yes	
Refrigerated Condensers	Use refrigerated condensers to increase product recovery and reduce excess fuel gas production				Yes	
Cracking Units						
Fluid Catalytic Cracking Units (see also: Stationary Combustion Sources; Fuel Gas System and Flares)						
Power/Waste Heat Recovery	Install or upgrade power recovery or waste heat boilers to recover latent heat from the FCCU regenerator exhaust				Yes	
High-Efficiency Regenerators	Use specially designed FCCU regenerators for high efficiency, complete combustion of catalyst coke deposits				Yes	

GHG Control Measure	Description	Efficiency Improvement/ GHG emission reduction	Retrofit Capital Costs (\$/unit of CO_2e)	Payback time (years)	Demon-strated in Practice?	Other Factors
Hydrocracking Units (see also: Stationary Combustion Sources; Fuel Gas System and Flares; Hydrogen Production Units)						
Power/Waste Heat Recovery	Install or upgrade power recovery to recover power from power can be recovered from the pressure difference between the reactor and fractionation stages			2.5 years	Yes	
Hydrogen Recovery	Use hydrogen recovery compressor and back-up compressor to ensure recovery of hydrogen in process off-gas				Yes	
Coking Units						
Fluid Coking Units (see also: Stationary Combustion Sources; Fuel Gas System and Flares)						
Power/Waste Heat Recovery	Install or upgrade power recovery or waste heat boilers to recover latent heat from the fluid coking unit exhaust				Yes	
Flexicoking Units (see: Stationary Combustion Sources; Fuel Gas System and Flares)						
Delayed Coking Units (see also: Stationary Combustion Sources; Fuel Gas System and Flares)						
Steam Blowdown System	Use low back-pressure blowdown system and recycle hot blowdown system water for steam generation				Yes	
Steam Vent	Lower pressure and temperature of coke drum to 2 to 5 psig and 230°F to minimize direct venting emissions	50 to 80% reduction in direct steam vent CH_4 emissions			Yes	
Catalytic Reforming Units (see also: Stationary Combustion Sources; Fuel Gas System and Flares; Hydrogen Production Units)						
Sulfur Recovery Units						
Sulfur Recovery System Selection	Evaluate energy and CO2 intensity in selection of sulfur recovery unit and tail gas treatment system and a variety of different tail gas treatment units including Claus, SuperClaus® and EuroClaus®, SCOT, Beavon/amine, Beavon/Stretford, Cansolv®, LoCat®, and Wellman-Lord				Yes	
Hydrogen Production Units						
Hydrogen Production Optimization	Implement a comprehensive assessment of hydrogen needs and consider using additional catalytic reforming units to produce H_2				Yes	
Combustion Air and Feed/Steam Preheat	Use heat recovery systems to preheat the feed/steam and combustion air temperature	5% of total energy consumption for H_2 production			Yes	

GHG Control Measure	Description	Efficiency Improvement/ GHG emission reduction	Retrofit Capital Costs ($/unit of CO_2e)	Payback time (years)	Demon-strated in Practice?	Other Factors
Cogeneration	Use cogeneration of hydrogen and electricity: hot exhaust from a gas turbine is transferred to the reformer furnace; the reformer convection section is also used as a heat recovery steam generator (HRSG) in a cogeneration design; steam raised in the convection section can be put through either a topping or condensing turbine for additional power generation				Yes	
Hydrogen Purification	Evaluate hydrogen purification processes (i.e., pressure-swing adsorption, membrane separation, and cryogenic separation) for overall energy intensity and potential CO_2 recovery.				Yes	
Hydrotreating Units (see also: Hydrogen Production Units; Sulfur Recovery Units)						
Hydrotreater Design	Use energy efficient hydrotreater designs and new catalyst to increase sulfur removal.				Yes	
Crude Desalting and Distillation Units						
Desalter Design	Alternative designs for the desalter, such as multi-stage units and combinations of AC and DC fields, may increase efficiency and reduce energy consumption.				Yes	
Progressive Distillation Design	Progressive distillation process uses as series of distillation towers working at different temperatures to avoid superheating lighter fractions of the crude oil.	30% reduction in crude heater emissions; 5% or more refinery-wide			Yes	
Storage Tanks						
Vapor Recovery or Control for Unstabilized Crude Oil Tanks	Consider use of a vapor recovery or control system for crude oil storage tanks that receive crude oil that has been stored under pressure ("unstabilized" crude oil)	90-95% reduction in CH_4 from these tanks			Yes	
Heated Storage Tank Insulation	Insulate heated storage tanks				Yes	

4.0 Energy Programs and Management Systems

Industrial energy efficiency can be greatly enhanced by effective management of the energy use of operations and processes. U.S. EPA's ENERGY STAR Program works with hundreds of manufacturers and has seen that companies and sites with stronger energy management programs gain greater improvements in energy efficiency than those that lack procedures and management practices focused on continuous improvement of energy performance.

Energy Management Systems (EnMS) provide a framework for managing energy and promote continuous improvement. The EnMS provides the structure for an energy program and its energy team. EnMS establish assessment, planning, and evaluation procedures which are critical for actually realizing and sustaining the potential energy efficiency gains of new technologies or operational changes.

Energy management systems promote continuous improvement of energy efficiency through:

- Organizational practices and policies,
- Team development
- Planning and evaluation,
- Tracking and measurement,
- Communication and employee engagement, and
- Evaluation and corrective measures.

For nearly 10 years, the U.S. EPA's ENERGY STAR Program has promoted an energy management system approach. This approach, outlined in **Figure 5**, outlines the basic steps followed by most energy management systems approaches.

(www.energystar.gov/guidelines)

Figure 5. ENERGY STAR Guidelines for Energy Management

In recent years, interest in energy management system approaches has been growing. There are many reasons for the greater interest. These include recognition that a lack of management commitment is an important barrier to increasing energy efficiency. Lack of an effective energy team and an effective program result in poor implementation of new technologies and poor implementation of energy assessment recommendations. Poor energy management practices that fail to monitor performance do not ensure that new technologies and operating procedures will achieve their potential to improve efficiency.

Approaches to implementing energy management systems vary. EPA's ENERGY STAR Guidelines for Energy Management are available for public use on the web and provide extensive guidance (see: www.energystar.gov/guidelines). Alternatively, energy management standards are available for purchase from ANSI, ANSI MSE 2001:200 and in the future from ISO, ISO 50001.

While energy management systems can help organizations achieve greater savings through a focus on continuous improvement, they do not guarantee energy savings or CO_2 reductions alone. Combined with effective plant energy benchmarking and appropriate plant improvements, energy management systems can help achieve greater savings.

There are a variety of factors to consider when contemplating requiring certification to an Energy Management Standard established by a standards body such as ANSI or ISO. First, energy management system standards are designed to be flexible. A user of the standard is able to define the scope and boundaries of the energy management system so that single production lines, single processes, a plant or a corporation could be certified. Beyond scope, achieving certification for the first time is not based on efficiency or savings (although re-certifications at a later time could be). Finally, cost is an important factor in the standardized approach. Internal personnel time commitments, external auditor and registry costs are expensive.

From a historical perspective, few companies have pursued certification according to the ANSI energy management standards to date. One reason for this is that the elements of an energy management system can be applied without having to achieve certification which adds additional costs. The ENERGY STAR Guidelines and associated resources are widely used and adopted partly because they are available in the public domain and do not involve certification.

Overall, a systems approach to energy management is an effective strategy for encouraging energy efficiency in a facility or corporation. The focus of energy management efforts are shifted from a "projects" to a "program" approach. There are multiple pathways available with a wide range of associated costs (ENERGY STAR energy management resources are public while the standardized approaches are costly). The effectiveness of an energy management system is linked directly to the system's scope, goals and measurement and tracking. Benchmarks are the most effective measure for demonstrating the system's achievements.

4.1 Sector-Specific Plant Performance Benchmarks

Benchmarking is the process of comparing the performance of one site against itself over time or against the range of performance of the industry. Benchmarking is typically done at a whole facility or site level to capture the synergies of different technologies, operating practices, and operating conditions and typically results in a calculation of the emissions intensity of a site, which are the emissions per unit of product.

For a refinery, emissions intensity is influenced by a number of factors, including energy efficiency, fuel use, feed composition, and products. While refineries all refine crude oil to make a range of common products (gasoline, diesel, fuel oils, liquefied petroleum gases), they often vary in size and the number of processing units that are operating. For example, refineries with more simple configurations may not be able to process certain fractions into more energy-intensive products. Likewise, refineries that process heavy sour crudes may require more energy intensive processing. Benchmarking approaches have been used in the refining industry for many years to improve efficiency and productivity. The European Union evaluated and concluded that the Solomon's complexity weighted barrel approach should be used to benchmark refineries as part of their methodology for allocating emission allowances in the European Union Emissions Trading System (Ecofys, 2009).

4.2 Industry Energy Efficiency Initiatives

The U.S. EPA's ENERGY STAR Program (www.energystar.gov/industry) and U.S. DOE's Industrial Technology Program (www.energy.gov/energyefficiency) have led industry specific energy efficiency initiatives over the years. These programs have helped to create guidebooks of energy efficient technologies, profiles of industry energy use, and studies of future technologies. Some states have also led sector specific energy efficiency initiatives. Resources from these programs can help to identify technologies that may help reduce CO_2 emissions.

EPA's ENERGY STAR Program has conducted an energy efficiency improvement assessment for petroleum refineries (Worrell and Galitsky, 2005). Many of the GHG reduction measures provided in the following sections are a result of this industry-specific assessment.

4.3 Energy Efficiency Improvements in Facility Operations

4.3.1 Monitoring and Process Control Systems

Most refineries already employ some energy management systems. At existing facilities, only a limited number of processes or energy streams may be monitored and managed. Opportunities should be evaluated for expanding the coverage of monitoring systems throughout the plant. New facilities should include a comprehensive energy management program (Worrell and Galitsky, 2005).

Process control systems are available for essentially all industrial processes. These control systems are typically designed to primarily improve productivity, product quality, and efficiency of a process. However, each of these improvements will lead to increased energy efficiency as well. Process control systems also reduce downtime, maintenance costs, and processing time, and increase resource efficiency and emission control (Worrell and Galitsky, 2005).

Although specific energy savings and payback periods are highly facility-specific, the application of monitoring systems to specific industrial applications have demonstrated energy savings of 4-17 percent, and process control systems can reduce energy consumption by 2-18 percent over facilities without such systems. In general, cost and energy savings of about 5 percent can be expected through the implementation of monitoring and process control systems (Worrell and Galitsky, 2005).

Valero and AspenTech have developed a system to model and control plant-wide energy usage for refinery operations. The system was installed at a domestic refinery and is expected to reduce overall energy usage by 2-8 percent (Worrell and Galitsky, 2005).

Process control systems for the CDU have been shown to reduce energy costs by $0.05-0.12/barrel (bbl) of feed, with paybacks of less than 6 months. Another CDU control system reduced energy consumption and flaring and increased throughput, resulting in a payback of about 1 year. In Portugal, a refinery installed advanced CDU controls and realized a 3-6 percent increase in throughput. The payback period for this control system was 3 months (Worrell and Galitsky, 2005).

Process control systems for FCCU are supplied by several companies. Cost savings range from $0.02-0 40.bbl of feed with paybacks ranging from 6-18 months. At one refinery, an existing FCCU control system was updated at a 65,000 bpd unit and a cost savings of $0.05/bbl of feed was realized. A refinery in Italy installed a control system on a FCCU and reduced cost by $0.10/bbl of feed with a payback of less than 1 year. (Worrell Galitsky, 2005)

In South Africa, a refinery installed a multivariable predictive control system on a hydrotreater. Hydrogen consumption was reduced by 12 percent and the fuel consumption of the heater was reduced by 18 percent. Improved yield of gasoline and diesel were also realized. The payback period was 2 months (Worrell and Galitsky, 2005).

4.3.2 High Efficiency Motors

Electric motors are used throughout the refinery for such applications as pumps, air compressors, fans, and other applications. Pumps, compressors and fans account for 70 to 80 percent of the total electricity usage at the refinery (Worrell and Galitsky, 2005). As such, a systems approach to energy efficiency should be considered for all motor systems (motors, drives, pumps, fans, compressors, controls). An evaluation of energy supply and energy demand could be performed to optimize overall performance. A systems approach includes a motor management plan that considers at least the following factors (Worrell and Galitsky, 2008):

- Strategic motor selection
- Maintenance
- Proper size
- Adjustable speed drives
- Power factor correction
- Minimize voltage unbalances

Pumps are the single largest electricity user at a refinery, accounting for about half of the total energy usage. One study estimated that 20 percent of the energy consumed by pump motors could be saved through equipment or control system changes. Implementation of maintenance programs for pump motors can reduce electricity use by 2-7 percent, with payback periods less than 1 year (Worrell and Galitsky, 2005).

Motor management plans and other efficiency improvements can be implemented at existing facilities and should be considered in the design of new construction. At existing facilities, replacing older motors with high efficiency motors are typically cost-effective when a motor needs replacement, but may not be economical when the old motor is still operational. Payback periods from energy savings are typically less than 1 year (Worrell and Galitsky, 2005).

4.3.3 Variable Speed Drives

Energy use on centrifugal systems such as pumps, fans, and compressors is approximately proportional to the cube of the flow rate. Therefore, small reductions in the flow may result in large energy savings. The use of variable speed drives can better match speed to load requirements of the motors. The installation of variable speed drives at new facilities can result in payback periods of just over 1 year (Worrell and Galitsky, 2005).

4.3.4 Optimization of Compressed Air Systems

Compressed air systems provide compressed air that is used throughout the refinery. Although the total energy used by compressed air systems is small compared to the facility as a whole, there are opportunities for efficiency improvements that will save energy. Efficiency improvements are primarily obtained by implementing a comprehensive maintenance plan for the compressed air systems. Worrell and Galitsky (2005, 2008) listed the following elements of a proper maintenance plan:

- Keep the surfaces of the compressor and intercooling surfaces clean
- Keep motors properly lubricated and cleaned
- Inspect drain traps
- Maintain the coolers
- Check belts for wear
- Replace air lubricant separators as recommended
- Check water cooling systems

In addition to the maintenance plan, reducing leaks in the system can reduce energy consumption by 20 percent. Reducing the air inlet temperature will reduce energy usage, and routing the air intake to outside the building can have a payback in 2-5 years. Control systems can reduce energy consumption by as much as 12 percent. Properly sized pipes can reduce energy consumption by 3 percent. Since as much as 93 percent of the electrical energy used by air compressor systems is lost as heat, recovery of this heat can be used for space heating, water heating, and similar applications (Worrell and Galitsky, 2005, 2008).

Air compressor system maintenance plans and other efficiency improvements can be implemented at existing facilities and should be considered in the design of new construction.

4.3.5 Lighting System Efficiency Improvements

Similar to air compressor systems, the energy used for lighting at a petroleum refinery facilities represent a small portion of the overall energy usage. However, there are opportunities for cost-effective energy efficiency improvements. Automated lighting controls that shut off lights when not needed may have payback periods of less than 2 years. Replacing T-12 lights with T-8 lights can reduce energy use by half, as can replacing mercury lights with metal halide or high pressure sodium lights. Substituting electronic ballasts for magnetic ballasts can reduce energy consumption by 12-25 percent (Worrell and Galitsky, 2005, 2008).

Lighting system improvements can be implemented at existing facilities and should be considered in the design of new construction.

5.0 GHG Reduction Measures by Source

5.1 Stationary Combustion Sources

5.1.1 Steam Generating Boilers

According to Worrell and Galitsky (2005), approximately 30 percent of onsite energy use at domestic refineries is used in the form of steam generated by boilers, cogeneration, or waste heat recovery from process units. The U.S. DOE estimated steam accounts for 38 percent of a refinery's energy needs (U.S. DOE, 2002). However, off-site purchases of steam represent only 3 to 5 percent of the total energy consumption at petroleum refineries nationwide (EIA, 2009). Given that steam accounts for 30 to 38 percent of a refinery's energy needs, it is evident that most refineries produce their own steam. As such, steam generation and distribution makes a significant contribution to a petroleum refinery's energy needs, and subsequently its on-site GHG emissions.

5.1.1.1 Systems Approach to Steam Generation

A thorough analysis of steam needs and energy recovery opportunities could be conducted to make the steam generation process as efficient as possible. For example, the analysis should assure that steam is not generated at pressures or volumes larger than what is needed. In those situations where the steam generation has limited adjustability, the excess energy in the steam should be recovered using a turbo expander or steam expansion turbine. Another option is to operate multiple boilers that are regulated according to steam demands. One refinery that implemented a program including scheduling of boilers on the basis of efficiency and minimizing losses in the turbines resulted in $5.4 million in energy savings (Worrell and Galitsky, 2005).

5.1.1.2 Boiler Feed Water Preparation

Boiler feed water is typically pre-treated to remove contaminates that foul the boiler. A refinery in Utah replaced a hot lime water softener with a reverse osmosis membrane treatment system to remove hardness and reduce alkalinity. Blowdown was reduced from 13.3 percent to 1.5 percent of steam produced. Additionally, reductions were seen in chemical usage, maintenance, and waste disposal costs. The initial investment of the membrane system was $350,000 and annual savings of $200,000 were realized (Worrell and Galitsky, 2005).

5.1.1.3 Improved Process Control

Boilers are operated with a certain amount of excess air to reduce emissions and for safety considerations. However, too much excess air may lead to inefficient combustion, and energy must be used to heat the excess air. Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture. Payback for such systems is typically about 0.6 years (Worrell and Galitsky, 2005).

5.1.1.4 Improved Insulation

The insulation of older boilers may be in poor condition, and the material itself may not insulate as well as newer materials. Replacing the insulation combined with improved controls can reduce energy requirements by 6-26 percent. Insulation on steam distribution systems should also be evaluated. Improving the insulation on the distribution pipes at existing facilities may reduce energy usage by 3-13 percent, with an average payback period of 1.1 years (Worrell and Galitsky, 2005).

5.1.1.5 Improved Maintenance

All boilers should be maintained according to a maintenance program. In particular, the burners and condensate return system should be properly adjusted and worn components replaced. Average energy savings of about 10 percent can be realized over a system without regular maintenance. Additionally, fouling on the fireside of the boiler and scaling on the waterside should be controlled (Worrell and Galitsky, 2005).

5.1.1.6 Recover Heat from Boiler Flue Gas

Flue gasses throughout the refinery may have sufficient heat content to make it economical to recover the heat. Typically, this is accomplished using an economizer to preheat the boiler feed water. One percent of fuel use can be saved for every 25 °C reduction in flue gas temperature. In some situations, the payback for installing an economizer is about 2 years (Worrell and Galitsky, 2005).

5.1.1.7 Recover Steam from Blowdown

The pressure drop during blowdown may produce substantial quantities of low grade steam that is suitable for space heating and feed water preheating. For boilers below 100 MMBtu/yr, fuel use can be reduced by about 1.3 percent, and payback may range from 1-2.7 years. A chemical plant installed a steam recover system to recover all of the blowdown steam from one process and realized energy savings of 2.8 percent (Worrell and Galitsky, 2005).

5.1.1.8 Reduce Standby Losses

It is common practice at most refineries to maintain at least one boiler on standby for emergency use. Steam production at standby can be virtually eliminated by modifying the burner, combustion air supply, and boiler feed water supply. Additionally, automatic control systems can reduce the time needed to reach full capacity of the boiler to a few minutes. These measures can reduce the energy consumption of the standby boiler by as much as 85 percent Worrell and Galitsky, 2005).

These measures were applied to a small 40 tonnes/hr steam boiler at an ammonia plant, resulting in energy savings of 54 TBtu/yr with a capital investment of about $270,000 (1999$). The payback period was 1.5 years (Worrell and Galitsky, 2005).

5.1.1.9 Improve and Maintain Steam Traps

Significant amounts of steam may be lost through malfunctioning steam traps. A maintenance plan that includes regular inspection and maintenance can reduce boiler energy usage by up to 10 percent (Worrell and Galitsky, 2005).

5.1.1.10Install Steam Condensate Return Lines

Reuse of the steam condensate reduces the amount of feed water needed and reduces the amount of energy needed to produce steam since the condensate is preheated. The costs savings can justify the cost of the condensate return lines. Estimates of energy savings are as high as 10 percent, with a payback period of 1.1 years for facilities with no or insufficient condensate return systems (Worrell and Galitsky, 2005).

5.1.2 Process Heaters

5.1.2.1 Draft Control

Excessive combustion air reduces the efficiency of process heater burners. At one domestic refinery, a control system was installed on three CDU furnaces to maintain excess air at 1 percent rather than the previous 3-4 percent. Energy usage of the burners was reduced by 3-6 percent and nitrogen oxide ($NO_{x)}$ emissions were reduced by 10-25 percent. The cost savings due to reduced energy requirements was $340,000. Regular maintenance of the draft air intake systems can reduce energy usage and may result in payback periods of about 2 months (Worrell and Galitsky, 2005). Draft control is applicable to new or existing process heaters, and is cost-effective for a wide range of process heaters (20 to 30 MMBtu/hr or greater).

5.1.2.2 Air Preheating

The flue gases of the furnace can be used to preheat the combustion air. Every 35 °F drop in exit flue gas temperature increases the thermal efficiency of the furnace by 1 percent. The resulting fuel savings can range from 8-18 percent, and may be economically attractive when the flue gas temperature is above 650 °F and the heater size is 50 MMBtu/hr or more. Payback periods are typically on the order of 2.5 years. One refinery in the United Kingdom installed a combustion air preheater on a vacuum distillation unit (VDU) and reduced energy costs by $109,000/yr. The payback period was 2.2 years (Worrell and Galitsky, 2005). Air preheating would require natural draft system to be converted to a forced draft system requiring installation of fans, which would increase electricity consumption and typically increase NO_X emissions. Consequently, several factors, including process heater size and draft type as well as secondary impacts, need to be considered retrofitting existing process heaters. Air preheating is often much more economical and effective when considered in the design of a new process heater.

5.1.3 Combined Heat and Power (CHP)

The large steam requirements for refining operations and the continuous operations make refineries excellent candidates for combined heat and power (CHP) generation. Refineries represent one of the largest industry sources of CHP today with 103 active CHP plants with an electric generation capacity of 14.6 gigawatts (ICF, 2010). Currently, about 60-70 percent of the 137 refineries operating at the beginning of 2010 use CHP (ICF International, 2010; EIA, 2009).

About 75 percent of the refinery CHP capacity comes from natural gas-fired combined cycle power plants consisting of large combustion turbines with heat recovery steam generators (HRSG) producing power and steam. A portion of the steam produced is used to generate more power in back pressure steam turbines. These plants meet the facility steam loads but often produce much more power than is needed by the facility itself, and, therefore, export power to the electric grid. The next most common type of CHP system is a combustion turbine with heat recovery. These systems make up about 11 percent of the existing refinery CHP capacity. Again, these systems are fueled mostly with natural gas, but internally generated fuels (*i.e*., refinery fuel gas) are also used. Most of the remaining system CHP capacity is boilers producing high pressure steam that run through a back-pressure steam turbine to produce power and lower pressure steam for process use. These systems generally do not use natural gas but, instead, are fired with a variety of internally generated fuels, waste fuels, and even coal.

While CHP systems are already in use at the majority of domestic refineries, there are significant remaining opportunities to add CHP-based on evaluation of steam requirements met by boilers and by CHP (Worrell and Galitsky, 2005). In addition, there are opportunities to repower existing CHP plants making them larger and more efficient by adding newer, more efficient combustion turbines and by converting existing simple cycle plants to combined cycle operation by adding steam turbines for additional power. Additionally, as refineries install flare gas recovery systems, they may need to install CHP systems to provide a productive source for utilizing the recovered fuel gas. There may be no direct CO_2 reductions at refineries from this technology, but indirect reductions from displacing grid power. The level of reduction is a function of the CO_2 intensity of the displaced external power production.

CHP systems require a fairly substantial investment ($1,000-2,500/kilowatt (kW)); however, the economics of CHP operation at refineries is generally very attractive. One refinery installed a 34 megawatt (MW) cogeneration unit in 1990 that consisted of two gas turbines and two heat recovery steam boilers. All facility electricity needs are met by the unit, and occasionally excess electricity is exported to the grid. Cost savings resulting from the onsite production of electricity were about $55,000/day. CHP can also be economical for small refineries. One study for an asphalt refinery showed that a 6.5 MW gas turbine CHP unit would reduce energy costs by $3.8 million/yr with a payback period of 2.5 years (Worrell and Galitsky, 2005).

5.1.4 Carbon Capture

The post-combustion technologies listed below are generally end-of-pipe measures. It should be noted that petroleum refineries emit CO_2 from a number of different process, and the exhaust stacks for these emission points are numerous and scattered across the facility. The consideration of CO_2 capture and control at a refinery would likely be limited to the larger CO_2 emitting stacks, such as the FCCU, the fluid coking unit, the hydrogen plant, and large boilers or process heaters.

5.1.4.1 Oxy-Combustion

Oxy-combustion is the process of burning a fuel in the presence of pure or nearly pure oxygen instead of air. Fuel requirements are reduced because there is no nitrogen component to be heated, and the resulting flue gas volumes are significantly reduced (Barker, 2009).

The process uses an air separation unit to remove the nitrogen component from air. The oxygen-rich stream is then fed to the combustion unit so the resulting exhaust gas contains a higher concentration of CO_2, as much as 80 percent. A portion of the exhaust stream is discharged to a CO_2 separation, purification, and compression facility. The higher concentration of CO_2 in the flue gas directly impacts size of the adsorber (or other separation technique), and the power requirements for CO_2 compression. This technology is still in the research stage. The

Petroleum Environmental Research Forum (PERF) is focusing on large refinery combustion sources, particularly the FCCU and crude oil process heaters.

5.1.4.2 Post-Combustion Solvent Capture and Stripping

Post-combustion capture using solvent scrubbing, typically using monoethanolamine (MEA) as the solvent, is a commercially mature technology. Solvent scrubbing has been used in the chemical industry for separation of CO_2 in exhaust streams (Bosoaga, 2009).

5.1.4.3 Post-Combustion Membranes

Membrane technology may be used to separate or adsorb CO_2 in an exhaust stream. It has been estimated that 80 percent of the CO_2 could be captured using this technology. The captured CO_2 would then be purified and compressed for transport. Initial projections of specific costs range from $55-63/tonne CO_2 avoided for cement manufacturing. The current state of this technology is primarily the research stage, with industrial application at least 10 years away. Positive aspects of membrane systems include very low maintenance (no regeneration required) (ECRA, 2009).

5.2 Fuel Gas Systems and Flares

5.2.1 Fuel Gas Systems

Many process units at the refinery, particularly atmospheric crude oil distillation, catalytic cracking, catalytic hydrocracking, thermal cracking, and coking processes, produce fuel gas that is commonly recovered for use in process heaters and boilers throughout the refinery. Typically a compressor is needed to recover the fuel gas at the fuel gas producing unit. The fuel gas generally needs to be treated to remove H_2S using amine scrubber systems. The remainder of the fuel gas system consists of piping and mix drums to transport the fuel gas to the various combustion sources at the refinery. Rather than repeating the GHG reduction measures for each potential fuel gas producing units, the GHG reduction measures for the fuel gas system are summarized here.

5.2.1.1 Compressor Selection

Different types of compressors have different propensities to leak. Based on emission factors for natural gas compressors, reciprocating compressors generally have approximately one-half the fugitive emissions of centrifugal compressors (U.S. EPA, 1999). Rod packing (e.g., Static-Pac) can be used to reduce fugitive emissions from reciprocating compressors, and dry seal centrifugal compressors have lower emissions (i.e., are less likely to leak) than those with wet seals (U.S. EPA, 1999). Thus, the projected methane emissions from fuel gas compressors could be considered in the selection of the type of compressor and fugitive controls used.

5.2.1.2 Leak Detection and Repair (LDAR)

LDAR programs have been used to reduce emissions of volatile organic compounds (VOC) from petroleum refineries for years. However, CH_4 is not a VOC, so current regulations do not generally require LDAR for refinery fuel gas systems or other high CH_4-containing gas streams. Leaks can be detected using organic vapor analyzers or specially designed cameras. LDAR programs commonly achieve emission reduction efficiencies of 80 to 90 percent; however, CH_4 emissions from leaking equipment components is expected to have a minimal contribution to the refinery's total GHG emissions.

5.2.1.3 Selection of Fuel Gas Sulfur Scrubbing System

Hydrogen sulfide in fuel gas is commonly removed by amine scrubbing. The scrubbing solution is typically regenerated by heating the scrubbing solution in a stripping column, typically using steam. The regeneration process can use significant energy, and the energy intensity (impacting CO_2 emissions) of the different processes should be considered (in conjunction with the sulfur scrubbing efficiencies) in selecting scrubbing technology. Some fuel gas, such as fuel gas produced by coking units, contain a significant quantity of other reduced sulfur compounds, such as methyl mercaptan and carbon disulfide, that are not removed by conventional amine scrubbing. The impact of these other reduced sulfur compounds on the resulting sulfur dioxide (SO_2) emissions from process heaters and other fuel gas combustion devices using coker-produced fuel gas should be considered for both energy efficiency (for GHG emission reductions) and total sulfur removal efficiency (for SO_2 emission reductions). Alternatives to conventional amine scrubbing (which uses dimethylethylamine, DMEA), include the use of proprietary scrubbing systems, such as FLEXSORB®, Selexol®, and Rectisol®, as well as using a mixture of solvents as in the Sulfinol process, additional conversion of sulfur compounds to H2S prior to scrubbing, or using a direct fuel gas scrubbing/sulfur recovery technology like LoCat® or caustic scrubbers.

CO_2 is also removed by amine scrubbing; however, this will not really impact the CO_2 emissions from the plant unless sulfur recovery occurs offsite because the CO_2 will be emitted either from the combustion unit receiving the fuel gas or from the sulfur recovery unit receiving the sour gas from the amine scrubbers. Therefore, the CO_2 scrubbing efficiency of the amine scrubbers is not important; however, some light hydrocarbons may also dissolve in the amine solution and subsequently sent to the sulfur recovery plant in the sour gas stream. Most hydrocarbons in the sour gas will eventually be oxidized in the sulfur recovery plant, so entrainment of hydrocarbons does lead to additional CO_2 emissions. Therefore, scrubbing systems could be evaluated based on their sulfur removal efficiency, energy efficiency, and ability to not entrain hydrocarbons. Note that higher sulfur removal efficiencies may have an energy penalty (*i.e.*, requiring more regeneration steam per pound of treated fuel gas), so a holistic analysis is needed when selecting the sulfur scrubbing system.

5.2.2 Flares

5.2.2.1 Flare Gas Recovery

Flaring can be reduced by installation of commercially available recovery systems, including recovery compressors and collection and storage tanks. Such systems have been installed at a number of domestic refineries. At one 65,000 bpd facility in Arkansas, two flare gas recovery systems were installed that reduced flaring almost completely. This facility will use flaring only in emergencies when the amount of flare gas exceeds the capacity of the recovery system. The recovered gas is compressed and used in the refinery's fuel system. The payback period for flare gas recovery systems may be as little as 1 year (Worrell and Galitsky, 2005). Similar flare gas recovery projects have been reported in the literature (John Zinc Co, 2006; Envirocomb Limited, 2006; Peterson *et al.*, 2007; U.S. DOE, 2005), reducing flaring by approximately 95 percent. Based on emission inventory presented by Lucas (2008), nationwide CO_2 emissions from flaring at petroleum refineries were estimated to be 5 million metric tons. Provided that the recovered fuel can off-set natural gas purchases, flare gas recovery is generally cost-effective for recovering routine flows of flare gas exceeding 20 MMBtu/hr (approximately

0.5 to 1-million scf per day, depending on heat content of flare gas). Based on these estimates, flare gas recovery could reduce nationwide CO_2 emissions from flares by 3-million metric tons. The cost-effectiveness of flare gas recovery is highly dependent on the heating value of the flare gas to be recovered and the price of natural gas. For refineries that may have excess fuel gas, a flare gas recovery system may also need to include a combined heat and power unit to productively use the recovered flare gas as described in Section 5.1.

5.2.2.2 Proper Flare Operation

Poor flare combustion efficiencies generally lead to higher methane emissions and therefore higher overall GHG emissions due to the higher global warming potential (GWP) of methane. Poor flare combustion efficiencies can occur at very low flare rates with high crosswinds, at very high flow rates (*i.e.*, high flare exit velocities), when flaring gas with low heat content, and excessive steam-to-gas mass flows. Installing flow meters and gas composition monitors on the flare gas lines and having automated steam rate controls allows for improved flare gas combustion control, and minimizes periods of poor flare combustion efficiencies.

5.2.2.3 Refrigerated Condensers for Process Unit Distillation Columns

For refineries that are rich in fuel gas, an alternative to a flare gas recovery system and CHP unit may be the use of a refrigerated condenser for distillation column overheads. Product recovery may be limited by the temperature of the distillation unit overhead condenser, causing more gas to be sent to the refinery fuel gas system and/or flare. The recovery temperature can be reduced by installing a waste heat driven refrigeration plant. A refinery in Colorado installed such a system in 1997 on a catalytic reforming unit distillation column and was able to recover 65,000 bbl/yr of LPG that was previously flared or used as a fuel. The payback of the system was about 1.5 years (Worrell and Galitsky, 2005).

5.3 Cracking Units

5.3.1 Catalytic Cracking Units

5.3.1.1 Power/Waste Heat Recovery

The most likely candidate for energy recovery at a refinery is the FCCU, although recovery may also be obtained from the hydrocracker and any other process that operates at elevated pressure or temperature. Most facilities currently employ a waste heat boiler and/or a power recovery turbine or turbo expander to recover energy from the FCCU catalyst regenerator exhaust. Existing energy recovery units should be evaluated for potential upgrading. One refinery replaced an older recovery turbine and saw a power savings of 22 MW and will export 4 MW to the power grid. Another facility replaced a turbo expander and realized a savings of 18 TBtu/yr (Worrell and Galitsky, 2005).

5.3.1.2 High-Efficiency Regenerators

High efficiency regenerators are specially designed to allow complete combustion of coke deposits without the need for a post-combustion device reducing auxiliary fuel combustion associated with a CO boiler.

5.3.1.3 Additional Considerations

Catalytic cracking units are significant fuel gas producers. As such, an FCCU can significantly alter the fuel gas balance of the refinery and may cause the refinery to be fuel gas rich (produce more fuel gas than it consumes) or increase the frequency of flare gas system overpressurization to the flare. GHG measures for fuel gas systems could be considered. Flare gas recovery for the impacted flare(s) could also be considered. Also, an FCCU will have a process heater to heat the feed, so GHG reduction measures for process heaters may also need to be considered. Finally, as FCCUs are one of the largest single CO_2 emission sources at a refinery, carbon capture techniques (Section 5.1.4) could be considered.

5.3.2 Hydrocracking Units

5.3.2.1 Power/Waste Heat Recovery

For hydrocracker units, power can be recovered from the pressure difference between the reactor and fractionation stages. In 1993, one refinery in the Netherlands installed a 910 kW power recovery turbine to replace the throttle at its hydrocracker unit at a cost of $1.2 million (1993$). The turbine produced about 7.3 million kilowatt hour per year (kWh/yr) and had a payback period of 2.5 years (Worrell and Galitsky, 2005).

5.3.2.2 Hydrogen Recovery

The hydrocracking unit is a significant consumer of hydrogen. Therefore, it is likely that a hydrocracking unit will significantly impact hydrogen production rates at the refinery (if the hydrogen production unit is captive to the refinery, i.e., under common ownership or control). The off-gas stream of the hydrocracker contains a significant amount of hydrogen, which is typically compressed, recovered, and recycled to the hydrocracking unit. When the recovery compressor fails or is taken off-line for maintenance, this high hydrogen gas stream is typically flared. A back-up recovery compressor could be considered for this high hydrogen stream. Although the flaring of hydrogen does not directly produce GHG, if natural gas is added to supplement the heating value of the flare gas, then flaring of the gas stream generates GHG. More importantly, the recovery of the hydrogen in this off-gas directly impacts the net quantity of new hydrogen that has to be produced for the unit. As hydrogen production has a large CO_2 intensity, continuous recovery of this high hydrogen gas stream can result in significant CO_2 emission reductions. At one Texas refinery, replacement of the hydrogen gas stream recovery compressor took 6 months, over which period approximately 7,000 tonnes of H_2 was flared, which corresponds to 63,000 to 70,000 tonnes of CO_2 emissions from additional hydrogen production. Considering the annualized capital cost of a back-up recovery compressor, the costs associated with the GHG emission reductions in this instance would be approximately $20 per tonne of CO_2 reduced.

5.3.2.3 Additional Considerations

Hydrocracking units produce fuel gas. As such, GHG measures for fuel gas systems are likely applicable for hydrocracking units. Additionally, flare gas recovery for the impacted flare(s) could be considered. The hydrocracking unit will have a process heater to heat the feed, so GHG reduction measures for process heaters may also need to be considered.

5.4 Coking Units

5.4.1 Fluid Coking Units

5.4.1.1 Power/Waste Heat Recovery

The fluid coking unit is an excellent candidate for energy recovery at a refinery. A CO boiler is used to combust the high CO off-gas from the fluid coking unit. Steam generation and/or a power recovery turbine or turbo expander could be used to recover energy from the CO boiler and its exhaust stream. Existing energy recovery units could be evaluated for potential upgrading.

5.4.1.2 Additional Considerations

Fluid coking units are significant fuel gas producers; GHG measures for fuel gas systems should be considered. Flare gas recovery for the impacted flare(s) could also be considered. The fluid coking unit will have a process heater to preheat the feed. Heat recovery systems could be considered for feed preheat; GHG reduction measures for process heaters may also need to be considered. Finally, as fluid coking units are one of the largest single CO_2 emission sources at a refinery, carbon capture techniques (Section 5.1.4) could be considered.

5.4.2 Flexicoking Units

Flexicoking coking units primarily produce a low-heating value fuel gas. Heat recovery from the produced gas stream should be used to preheat feed or to generate steam. The low-heating value fuel gas is typically combusted in specialized boilers and the GHG reduction measures for boilers could be reviewed. Also, flare gas recovery for the impacted flares and GHG reduction measures for process heaters may also need to be considered.

5.4.3 Delayed Coking Units

5.4.3.1 Steam Blowdown System

Delayed coking units use steam to purge and cool coke drums that have been filled with coke as the first step in the decoking process. A closed blowdown system for this steam purge controls both VOCs and methane. The steam to the blowdown system from a DCU will contain significant concentrations of methane and light VOCs. These systems could be enclosed to prevent fugitive emissions from the offgas or collected water streams. The noncondensibles from the blowdown system could be either recovered or directly sent to a combustion device, preferably a process heater or boiler rather than a flare to recover the energy value of the light hydrocarbons. Note that the sulfur content of this gas may prevent its direct combustion without treatment to remove sulfur.

As noted previously in Section 5.1.1.7 (regarding steam generating boilers), the blowdown system could be designed to operate at low pressures, so the DCU can continue to purge to the blowdown system rather than to atmosphere for extended periods. Also, a recovery unit to recycle hot blowdown system water for steam generation should be evaluated to improve the energy efficiency associated with the DCU’s steam requirements.

5.4.3.2 Steam Vent

The DCU “steam vent” is potentially a significant emission source of both methane and VOCs. While not completely understood, the emissions from this vent are expected to increase based on the coke drum vessel pressure and the average temperature when the steam off-gas is first diverted to the atmosphere at (rather than to the blowdown system) at the end of the coke drum purge and cooling cycle. Generally, cycle times of 16 to 20 hours are needed to purge, cool, and drain the coke drum vessels, cut the coke out, and preheat the vessel prior to receiving feed. In efforts to increase throughput of the unit, reduced cycle times are used, but this generally requires depressurization of the coke drum at higher temperatures and pressures leading to higher emissions. While larger coke drums may have slightly higher emissions than smaller coke drums, the temperature of the coke drum when the drum is first vented to atmosphere will have a more significant impact on the volume of gas vented to the atmosphere than does the size (volume) of the coke drum. Cycle times of less than 16 hours are an indicator that the purging/quench cycles may be too short, leading to excessive and unnecessary VOC and CH_4 emissions. 40 CFR Part 60 subpart Ja requires new DCU to not vent to the atmosphere until a vessel pressure of 5 psig or less is reached. At this pressure, the equilibrium coke bed temperature should be approximately 230°F. However, as the vessel will be continuously purging to the blowdown system, the bed temperature may be significantly higher even though the pressure of the vessel is below 5 pounds per square inch gauge (psig) depending on the cycle time. A DCU could be designed to allow depressurization to very low pressures (*e.g.*, 2 psig) prior to having to go to atmosphere (which will impact the blowdown system design) to allow flexibility in operation. Analysis of the CH_4 and VOC emissions at different temperatures and pressures could be conducted to determine operational parameters for the DCU depressurization/steam vent.

5.4.3.2 Additional Considerations

Delayed coking units are significant fuel gas producers. As such, GHG measures for fuel gas systems and flares could be considered. The fluid coking unit will have a process heater to preheat the feed. Heat recovery systems could be considered for feed preheat; GHG reduction measures for process heaters may also need to be considered.

5.5 Catalytic Reforming Units

The catalytic reforming unit is a net producer of hydrogen, so it can be considered as a means to produce hydrogen needed for other processes at the petroleum refineries; more detailed discussion of this is provided in Section 5.7. The reforming reaction is endothermic, so the catalytic reforming unit has large process heaters to maintain the reaction; GHG reduction measures for the process heaters could be considered. The catalytic reforming unit will also produce fuel gas so that GHG reduction measures for fuel gas systems and flares could be considered.

5.6 Sulfur Recovery Units

Nearly all refineries use the Claus-based sulfur recovery units, although some small refineries use LoCat™ system. There are, however, some variations on the traditional Claus system (*e.g.*, SuperClaus® and EuroClaus®) and a variety of different tail gas treatment units that are used in conjunction with the Claus sulfur recovery systems (*e.g.*, SCOT, Beavon/amine; Beavon/Stretford; Cansolv®, LoCat®, and Wellman-Lord). The energy and CO_2 intensities of these different systems could be evaluated (in conjunction with their sulfur recovery efficiencies) for sulfur recovery systems.

5.7 Hydrogen Production Units

Hydrotreating and hydrocracking units consume hydrogen. Hydrogen is produced as a by-product in catalytic reforming units. Hydrogen may also be produced specifically in captive or merchant hydrogen production units, which typically use steam methane reforming (SMR) techniques. Due to the importance of hydrogen for key processes and the interlinking of processes, a facility-wide hydrogen assessment could be performed to assess energy and GHG improvements that can be made. This assessment could include an assessment of whether additional catalytic reforming capacity can meet the hydrogen needs. Although both catalytic reforming and SMR are endothermic and require significant heat input, catalytic reformers produce high octane reformate (cyclic and aromatic hydrocarbons) rather than CO_2 as a result of the reforming reactions. Therefore, catalytic reforming provides a less CO_2-intensive means of producing hydrogen as compared to SMR hydrogen production. However, there is a limited quantity of naphtha and a limited need for reformate, so catalytic reforming may not be a viable option for meeting all of the hydrogen demands of the refinery.

If a hydrogen production unit is necessary, SMR technology appears to be the most effective means of producing additional hydrogen at this time. The following technologies could be considered for SMR hydrogen production units.

5.7.1 Combustion Air and Feed/Steam Preheat

Heat recovery systems can be used to preheat the feed/steam and combustion air temperature. If steam export needs to be minimized, an increase in the combustion air and feed/steam temperature through the convective section of the reformer is an option that can reduce fuel usage by 42 percent and steam export by 36 percent, and result in a total energy savings of 5 percent compared to a typical SMR (ARCADIS, 2008).

5.7.2 Cogeneration

Cogeneration of hydrogen and electricity can be a major enhancement of energy utilization and can be applied with SMR. Hot exhaust from a gas turbine is transferred to the reformer furnace. This hot exhaust at ~540 °C still contains ~13-percent oxygen and can serve as combustion air to the reformer. Since this stream is hot, fuel consumption in the furnace is reduced. The reformer convection section is also used as a HRSG in a cogeneration design. Steam raised in the convection section can be put through either a topping or condensing turbine for additional power generation. This technology is owned by Air Products and Technip, and has been applied at six hydrogen/cogeneration facilities for refineries (ARCADIS, 2008).

5.7.3 Hydrogen Purification

There are three main hydrogen purification processes. These are pressure-swing adsorption, membrane separation, and cryogenic separation. The selection of the purification method depends, to some extent, on the purity of the hydrogen produced. Pressure-swing adsorption provides the highest purity of hydrogen (99.9+ percent), but all of these purification methods can produce 95 percent or higher purity hydrogen stream. When lower purity (i.e., 95%) hydrogen gas is acceptable for the refinery applications, then any of the purification methods are technically viable. In such cases, the energy and CO_2 intensity of the various purification techniques could be considered. The purification technique also impacts the ease by which CO_2 recovery and capture can be used. See also the carbon capture techniques in Section 5.1.4.

5.8 Hydrotreating Units

A number of alternative hydrotreater designs are being developed to improve efficiency. New catalysts are being developed to increase sulfur removal, and reactors are being designed to integrate process steps. While many of these designs have not yet been proven in production, others such as oxidative desulfurization and the S Zorb process have been demonstrated at refineries. The design of both modifications and new facilities could consider the current state of the art (Worrell and Galitsky, 2005). Hydrotreaters consume hydrogen, so new hydrotreating units may also increase hydrogen production at the facility (see Section 5.7). Hydrotreaters also produce sour gas so the GHG reduction options discussed for sulfur scrubbing technologies (Section 5.2.1.3) and sulfur recovery units (Section 5.6) could be considered.

5.9 Crude Desalting and Distillation Units

Before entering the distillation tower, crude undergoes desalting at temperature ranging from 240 to 330 °F. Following desalting, crude enters a series of exchangers, known as preheat train to raise the temperature of the crude oil to approximately 500 °F. A direct-fired furnace is typically then used to heat the crude oil to between 650 and 750 °F before the crude oil is transferred to the flash zone of the tower. The crude oil furnaces are among the largest process heaters at the refinery; GHG reduction measures for these furnaces could be considered. Also, as the crude distillation unit employs among the largest process heaters at a refinery, carbon capture techniques (Section 5.1.4) could be considered. Additional GHG reduction measures are described below.

5.9.1 Desalter Design

Alternative designs for the desalter, such as multi-stage units and combinations of AC and DC fields, may increase efficiency and reduce energy consumption (Worrell and Galitsky, 2005).

5.9.2 Progressive Distillation Design

In the conventional scheme, all the crude feed is heated to a high temperature through the furnace prior to entering the atmospheric tower. Some lighter components of crude are superheated in the furnace, resulting in an irreversible energy waste. The progressive distillation process uses a series of distillation towers working at different temperatures (see **Figure 6**). The advantage of progressive distillation is that it avoids superheating of light fractions to temperatures higher than strictly necessary for their separation. The energy savings with progressive distillation has been reported to be approximately 30 percent (ARCADIS, 2008). Crude heaters account for approximately 25 percent of process combustion CO_2 emissions (Coburn, 2007); therefore, progressive distillation can reduce nationwide GHG emissions from petroleum refineries by almost 5 percent.

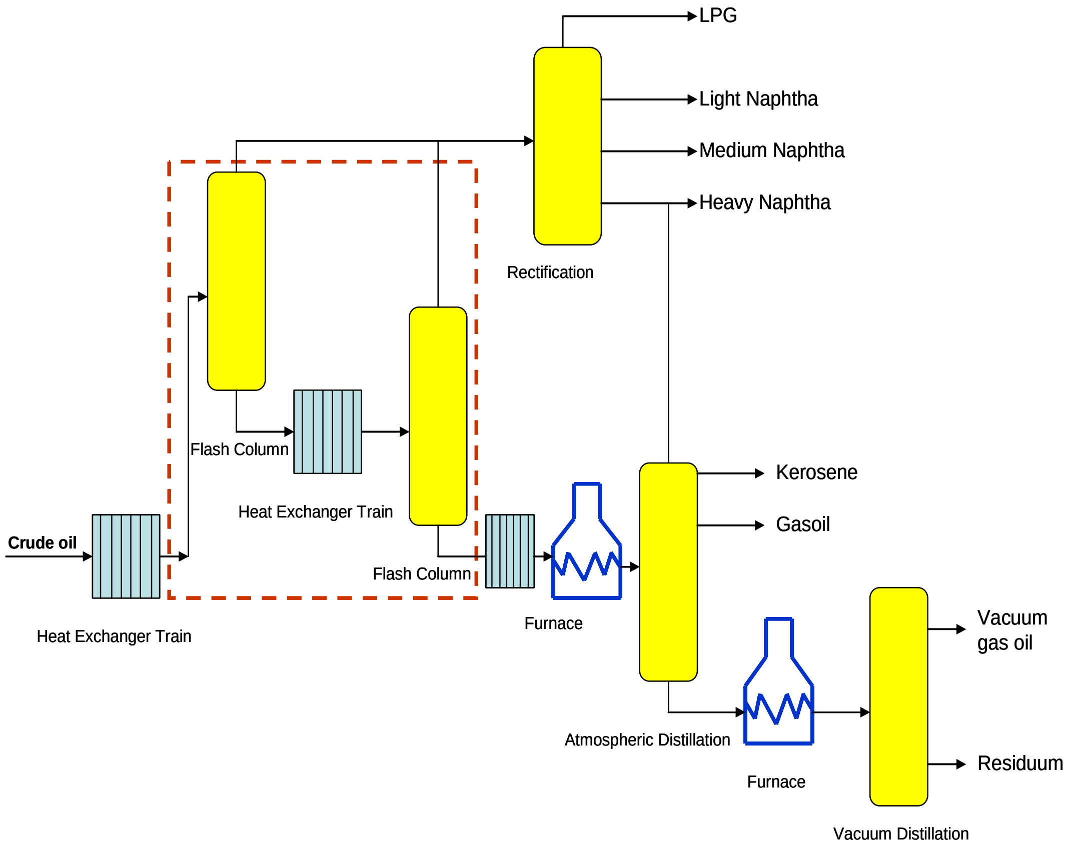

Figure 6. Process schematic of a progressive distillation process (from ARCADIS, 2008).

5.10 Storage Tanks

5.10.1 Vapor Recovery or Control for Unstabilized Crude Oil Tanks

Crude oil often contains methane and other light hydrocarbons that are dissolved in the crude oil because the crude oil is "stored" within the wells under pressure. When the crude oil is pumped from the wells and subsequently stored at atmospheric pressures, CH_4 and other light hydrocarbons are released from the crude oil and emitted from the atmospheric storage tanks. Most refineries receive crude oil that has been stored for several days to several weeks at atmospheric pressures prior to receipt at the refinery. These stabilized crude oils have limited GHG emissions. If a refinery receives crude oil straight from a production well via pipeline without being stored for several days at atmospheric pressures, the crude oil may contain significant quantities of methane and light VOC. When this "unstabilized" crude oil is first stored at the refinery at atmospheric conditions, the methane and gaseous VOC will evolve from the crude oil. Common tank controls, such as floating roofs, are ineffective at reducing these emissions. If a refinery receives unstabilized crude oil, a fixed roof tank vented to a gas recovery system of control device could be considered to reduce the GHG (particularly CH_4) emissions from these tanks.

5.10.2 Heated Storage Tank Insulation

Some storage tanks are heated to control viscosity of the stored product. A study at a refinery found that insulating an 80,000 bbl storage tank that is heated to 225 °F could save $148,000 in energy costs (Worrell and Galitsky, 2005).

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COMPREHENSIVE REPORT
Report Date:10/31/2013

Facility Information

RBLC ID:	LA-0271 (draft)	**Date Determination**	
		Last Updated:	10/10/2013
Corporate/Company Name:	CROSSTEX PROCESSING SERVICES, LLC	**Permit Number:**	PSD-LA-771
Facility Name:	PLAQUEMINE NGL FRACTIONATION PLANT	**Permit Date:**	05/24/2013 (actual)
Facility Contact:	BLAKE PHILLIPS (469) 308-6225 EHSDEPT@CROSSTEXENERGY.COM	**FRS Number:**	
Facility Description:	Facility fractionates inlet natural gas liquids into constituent product streams for sale.	**SIC Code:**	1321
Permit Type:	A: New/Greenfield Facility	**NAICS Code:**	211112
Permit URL:			
EPA Region:	6	**COUNTRY:**	USA
Facility County:	IBERVILLE		
Facility State:	LA		
Facility ZIP Code:	70764		
Permit Issued By:	LOUISIANA DEPARTMENT OF ENV QUALITY (Agency Name) MR. BRYAN D. JOHNSTON(Agency Contact) (225)219-3450 BRYAN.JOHNSTON@LA.GOV		
Other Agency Contact Info:	Pemit writer: Doug McCurry, (225) 219-3417		
Permit Notes:			

Process/Pollutant Information

PROCESS NAME: Heat Medium Oil (HMO) Heaters (HMO-01 & HMO-02)

Process Type: 12.310 (Natural Gas (includes propane and liquefied petroleum gas))

Primary Fuel: Natural gas

Throughput: 177.00 MM Btu/hr

Process Notes: Natural gas: 175 MM Btu/hr Process gas: 2 MM Btu/hr

POLLUTANT NAME: Carbon Dioxide Equivalent (CO2e)

CAS Number: CO2e

Test Method: Unspecified

Pollutant Group(s): (Greenhouse Gasses (GHG))

Emission Limit 1:

Emission Limit 2:

Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (P) Improved combustion measures: heater tuning, optimization, and installation of instrumentation and controls; insulation installed according to the heater manufacturer's specifications; operational monitoring as well as proper maintenance in order to minimize air infiltration.

Est. % Efficiency:

Cost Effectiveness: 0 $/ton

Incremental Cost Effectiveness: 0 $/ton

Compliance Verified: Unknown

Pollutant/Compliance Notes:

Process/Pollutant Information

PROCESS NAME: Mol Sieve Dehy Regen Heater (H-01)

Process Type: 13.310 (Natural Gas (includes propane and liquefied petroleum gas))

Primary Fuel: Natural gas

Throughput: 30.00 MM Btu/hr

Process Notes:

POLLUTANT NAME: Carbon Dioxide Equivalent (CO2e)

CAS Number: CO2e

Test Method: Unspecified

Pollutant Group(s): (Greenhouse Gasses (GHG))

Emission Limit 1:

Emission Limit 2:

Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (P) Improved combustion measures: heater tuning, optimization, and installation of instrumentation and controls; insulation installed according to the heater manufacturer's specifications; operational monitoring as well as proper maintenance in order to minimize air infiltration.

Est. % Efficiency:

Cost Effectiveness: 0 $/ton

Incremental Cost Effectiveness: 0 $/ton

Compliance Verified: Unknown

Pollutant/Compliance Notes:

Process/Pollutant Information

PROCESS NAME: Process Flare (FLARE-01)

Process Type: 19.390 (Other Flares)

Primary Fuel: Waste gas

Throughput: 26.00 MM Btu/hr

Process Notes: Waste gas: 21 MM Btu/hr Amine regenerator overhead gas: 4 MM Btu/hr Natural gas (pilot): 1 MM Btu/hr

POLLUTANT NAME: Carbon Dioxide Equivalent (CO2e)

CAS Number: CO2e

Test Method: Unspecified

Pollutant Group(s): (Greenhouse Gasses (GHG))

Emission Limit 1:

Emission Limit 2:

Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (P) Clean burning fuels, proper design and operation, and good combustion practices

Est. % Efficiency:

Cost Effectiveness: 0 $/ton

Incremental Cost Effectiveness: 0 $/ton

Compliance Verified: Unknown

Pollutant/Compliance Notes:

Process/Pollutant Information

PROCESS NAME: Emergency Flare (FLARE-02)

Process Type: 19.390 (Other Flares)

Primary Fuel: Natural gas

Throughput: 2.00 MM Btu/hr

Process Notes:

POLLUTANT NAME: Carbon Dioxide Equivalent (CO2e)

CAS Number: CO2e

Test Method: Unspecified

Pollutant Group(s): (Greenhouse Gasses (GHG))

Emission Limit 1:

Emission Limit 2:

Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (P) Clean burning fuels, proper design and operation, and good combustion practices

Est. % Efficiency:

Cost Effectiveness: 0 $/ton

Incremental Cost Effectiveness: 0 $/ton

Compliance Verified: Unknown

Pollutant/Compliance Notes:

Process/Pollutant Information

PROCESS NAME: Fugitive Emissions (FUG-01)

Process Type: 50.002 (Natural Gas/Gasoline Processing Plants)

Primary Fuel:

Throughput: 0

Process Notes:

POLLUTANT NAME: Carbon Dioxide Equivalent (CO2e)

CAS Number: CO2e
Test Method: Unspecified
Pollutant Group(s): (Greenhouse Gasses (GHG))
Emission Limit 1:
Emission Limit 2:
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:
Control Method: (P) Compliance with LDAR programs under 40 CFR 60 Subpart OOOO, LAC 33:III.2111, and LAC 33:III.2122
Est. % Efficiency:
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

Statement of Basis
Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for Channel Energy Center (CEC), LLC

Permit Number: PSD-TX-955-GHG

August 2012

This document serves as the Statement of Basis 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 November 3, 2011, the Channel Energy Center (CEC), LLC, submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions from proposed construction of a natural gas-fired combined-cycle combustion turbine generator (CTG) at the existing CEC facility. In connection with the same proposed project, CEC submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on November 3, 2011. On December 11, 2011, February 7, April 2, April 30, and June 22, 2012 respectively, CEC submitted additional information to amend their permit applications to both EPA and TCEQ, revising the permit applications to incorporate a multiphase construction of the proposed CTG. The revised project at the CEC plant proposes phased construction of the natural gas-fired combined-cycle CTG with a generating capacity of approximately 180 megawatts that will be completed in two stages of construction. In the initial phase, CEC intends to construct a Siemens Model FD2 combustion turbine that will be subsequently upgraded in performance as a FD3-series combustion turbine in the second stage of construction. Modification of the FD2 combustion turbine to the FD3-series would commence within eighteen (18) months of completion of construction or beginning of commercial operation of the initial project. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize phased construction of air emission sources at CEC.

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 CEC'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 EPA requested and provided by CEC and EPA's own technical analysis. EPA is making all this information available as part of the public record.[1]

II. Applicant

Channel Energy Center, LLC
717 Texas, Suite 1000
Houston, TX 77002

Physical Address:
451 Light Company Road
Pasadena, TX 77506

Contact:
Patrick Blanchard
Director, Environmental Services
Calpine Corporation
717 Texas, Suite 1000
Houston, TX 77002

III. 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). 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

[1] Note: Calpine intends to construct a nearly identical combustion turbine generator/heat recovery steam generator at their other Harris County facility, Deer Park Energy Center (DPEC), permit number PSD-TX-979-GHG, with a phased construction plan to install a Siemens FD2 series combustion turbine first, followed by the subsequent upgrade to the FD3 series, all within similar timeframes of the CEC permit. Calpine Corporation submitted both permit applications of DPEC and CEC to EPA, Region 6 within one month of each other. Hence, much of the information concerning the Calpine DPEC GHG permit (Permit Number: PSD-TX-955-GHG) and the resulting BACT analysis is similar to the information presented in the Calpine CEC GHG permit and CEC's BACT analysis.

The EPA, Region 6 Permit Writer is:
Alfred C. "AC" Dumaual, Ph.D.
Air Permitting Section (6PD-R)
(214) 665-6613

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

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IV. Facility Location

The CEC plant is located in Harris County, Texas, and this area is currently considered to be in attainment for all NAAQS with the exception of the 8 hour Ozone standard, for which it is classified as a marginal non-attainment area as of April 2012. The geographic coordinates for this facility are as follows:

Latitude:	29° 43' 08"	North	(29.718889)
Longitude:	95° 13' 55"	West	(-95.231944)

The figures below illustrate the facility location for this draft permit in city of Pasadena, Harris County, Texas.

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

EPA concludes Calpine's proposed modification is subject to PSD review for the pollutant GHG, because the project would lead to an emissions increase of GHGs for a facility as described at 40 CFR §§ 52.21(b)(23) and (49)(iv). Under the project, GHG emissions are calculated to increase over zero tons per year (tpy) on a mass basis and well exceed the applicability threshold of 75,000 tpy CO_2e. (EPA calculates CO_2e emissions of 1,045,635 tpy in the initial phase of construction which is increased to 1,060,783 tpy after the final phase of construction). 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 modification is subject to PSD review for non-GHG pollutants. Accordingly, under the circumstances of this project, the State will issue the non-GHG portion of the permit and EPA will issue the GHG portion.[2]

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 not required the applicant to model or conduct ambient monitoring for GHGs, and EPA Region 6 has not 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. We note again, however, that the project has triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD permit sought from TCEQ.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow the Channel Energy Center to initiate a multiphase construction of a new 180 MW natural gas-fired Siemens 501 F-series combined-cycle combustion turbine generator, identified as CTG3, with a plant-wide generating capacity of approximately 750-850 MW following the modification, depending on ambient conditions. The construction for this project will be carried out in two stages. In the initial stage, CEC proposes to construct a natural gas-fired Siemens 168 MW FD2 combined-cycle combustion turbine as described above upon issuance of the PSD GHG permit. In the final stage, the FD2 combustion turbine will be upgraded to a 180 MW FD3 combustion turbine, this involves replacement of a limited number of internal components of the turbine which will be accomplished in the timeframe of a routine outage. The modification includes improvements to the turbine blades, vanes and improved compressors seals that allow the turbine to regain generation capacity that is lost in the summer months due to hot ambient conditions. CEC plans to install the turbine using the FD2 configuration to ensure the project is online and available to supply needed power to the Electric Reliability Council of Texas (ERCOT) grid for the summer of 2014 peak season. Additional time may be required to install the parts required for an FD3 configuration, and hence

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[2] U.S. Environmental Protection Agency, *Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities*, April 19, 2011.< http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf> (April 2011).

a two-stage construction period is required to avoid compromising the scheduled construction and installation of the combustion turbine.

CEC intends to complete the upgrade of the Siemens 501 FD2-series engine to the FD3-series within an eighteen (18) month period following commercial operation of the FD2 series unit.. Completion of construction of the initial project will occur the date that commercial operation of the FD2 phase of the project begins, or no later than eighteen (18) months after initial testing is completed in order to account for any additional work that may take place during the "shakedown period" that immediately follows first fire of the proposed turbine. The increased changes in CO_2 emissions due to this modification are presented in the calculations of the original application as submitted on October 28, 2011. It was calculated that the proposed combustion turbine is an FD3-series engine will generate more CO_2 emissions than the FD2-series; however, the efficiency in terms of heat rate (in Btu/kWh) is the same for both configurations. Some or all of the steam produced from the new combustion turbine will either exhaust to a dedicated Heat Recovery Steam Generator (HRSG) to produce steam or be sold to a neighboring facility. The steam produced from the HRSG is then routed to an existing shared 200 MW steam turbine unit to produce electricity for sale to the ERCOT power grid. CTG3 will be fired exclusively with pipeline-quality natural gas. However, the duct burners associated with HRSG3 will be fueled by either pipeline-quality natural gas or "off" gas provided by an adjacent refinery or a mixture of the two. Listed in the table below is a summary of the emissions for this project, a detailed analysis of the calculations can be found in the Statement of Basis Appendix, Tables 1 through 8:

Total GHG Potential Emissions – Phase 1 of Construction			
	Potential Emissions (Mass Basis) TPY		**CO_2e Potential Emissions TPY**
CO_2	984,393	**CO_2**	984,393
CH_4	25.66	**CH_4**	539
N_2O	1.82	**N_2O**	565
SF_6	0.00018	**SF_6**	4.3
Total Potential Emissions (Mass Basis)	**984,421**	**Total CO_2e**	**985,501**
Total GHG Potential Emissions – Phase 2 of Construction			
	Potential Emissions (Mass Basis) TPY		**CO_2e Potential Emissions TPY**
CO_2	1,002,391	**1,002,39**	1,002,391
CH_4	26.00	**CH_4**	546
N_2O	1.86	**N_2O**	575
SF_6	0.00018	**SF_6**	4.3
Total Potential Emissions (Mass Basis)	**1,002,419**	**Total CO_2e**	**1,003,516**

VII. 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 takes 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 unit submitted in the PSD GHG application was evaluated separately in the top-down 5-step BACT analysis.

VIII. Applicable Emission Units Subject to BACT

The following devices are subject to this GHG PSD permit:

- Natural Gas-Fired Combined-cycle Combustion Turbine Generator (CTG3) and Heat Recovery Steam Generator (HRSG3)
- Fugitive Natural Gas emissions from piping components (NG-FUG)
- SF_6 Insulated Electrical Equipment (SF6-FUG)

IX. GHG BACT for the Natural-Gas Fired Combined-Cycle Combustion Turbine Generator (CTG3) and Heat Recovery System Generator (HRSG3)

The new combined-cycle combustion turbine generator (CTG) is proposed to be as efficient, but with improved environmental controls, compared to the other two existing CTG at the site. If approved, initially, a Siemens 501 FD2-series combined-cycle combustion generator with a generating capacity of approximately 168 MW will be constructed and will be upgraded to a FD3-series with a electrical generating capacity of 180 MW within an 18-month period under terms of conditions of the permit. The FD3 upgrade includes improvements to the turbine blades and vanes and improved compressor seals to allow the turbine to regain generation capacity that is lost during the summer months due to hot ambient conditions. The FD3-series combustion turbine will generate more CO_2 emissions on an annual basis than the FD2-series; however the efficiency, in terms of heat rate (in Btu/kWh), is the same for both series. The CTG will be fired exclusively with pipeline-quality natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf). However, the duct burners associated with the HRSG will be fueled by either pipeline-quality natural gas or "off" gas provided by an adjacent refinery or a mixture of the two. With regards to BACT, the CTG3 and HRSG3 are treated as one emission unit.

EPA has reviewed CEC's BACT analysis for the two-stage construction of a natural gas-fired combined-cycle combustion turbine generator and has incorporated portions of it into EPA's proposed BACT analysis, as summarized below.

<u>Step One: Identify All Potentially Available Control Technologies</u>

As part of the PSD review, CEC provides in the GHG permit application a 5-step top-down BACT analysis for the new combustion turbine emission unit. In this analysis, the following technologies are identified in the BACT analysis:

(A) the use of carbon capture and storage (CCS) including CO_2 capture/compression, CO_2 transport and CO_2 storage;
(B) Inherently lower-emitting processes, practices, and designs which are further subdivided into:
   (1) Combustion turbine energy efficiency processes, practices and designs;
   (2) Heat recovery steam generator energy efficiency process, practices and designs; and
   (3) Plant-wide energy efficiency processes, practices, and designs;

(A) Carbon Capture and Storage

For purposes of the BACT analysis, CCS is classified as an add-on pollution control technology for "facilities emitting CO_2 in large concentrations, 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)."[3] CCS involves the

[3]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)

separation and capture of CO_2 from the combustion process flue gas, the pressurizing of the captured CO_2 and then the transportation of the compressed CO_2 by pipeline or other means of transportation, if necessary, where it is injected into a long-term geological location. Several 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 following table adopted from IPCC's *Carbon Dioxide Capture and Storage*[4] report:

CCS Component	**CCS Technology**
Capture	Post-combustion
	Pre-combustion
	Oxy-fuel 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)
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 capture configurations – pre-combustion capture, post-combustion capture, and oxy-combustion capture:

1) Pre-combustion capture implies as named, the capture of CO_2 prior to combustion. It is a technological option available to integrated coal gasification combined-cycle (IGCC) plants. In these plants, coal is gasified to form synthesis gas (syngas with key components of carbon monoxide and hydrogen). Carbon monoxide (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. Primarily for coal-fired power plants and electric generating units (EGU), other industries can benefit. Currently, all commercial post-

[4] 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>

combustion capture is via chemical absorption process using monoethanolamine (MEA)-based solvents.[5]

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 air. The remainder of the flue gas, that is not recirculated, is rich in carbon dioxide and water vapor, which is treated by condensation of the water vapor to capture the CO_2.[6] When combusting coal with air (which is done in nearly all existing coal-burning power plants), nitrogen is formed as byproduct of the combustion and is present in high concentrations in the flue gas. Post-combustion capture of CO_2 is essentially the separation of nitrogen and carbon dioxide, 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[7]. It is implied that an optimized oxy-combustion power plant will have ultra-low CO_2 emissions as a result.

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, in most cases, a geological storage area. It is also possible that CO_2 can be stored and shipped via all different modes of transportation via land, air and sea.

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.[8]

(B) Inherently lower-emitting processes, practices, and designs

Methods techniques and systems to increase energy efficiency is the key GHG reducing direction that falls under "lower polluting processes/practices." Use of inherently lower-emitting technologies, including energy efficiency measures, represents an opportunity for GHG reductions in these types of BACT reviews. In some cases, a more energy efficient process or project design may be used effectively alone; where in other cases, energy efficient measure may be used effectively in tandem with end-of-stack controls to achieve additional control criteria pollutants. Applying the most energy efficient technologies at a source should in most cases translate into fewer overall emissions of all air pollutants per unit

[5] 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>
[6] 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>
[7] Herzog et al., page 4-5
[8] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, , February 2011
<http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>

of energy produced. Selecting technologies, measures and options that are energy efficient translates not only in the reduction of emissions of the particular regulated NSR air pollutant undergoing BACT review, but it also may achieve collateral reductions of emissions of other pollutants as well as GHGs.

Inherently lowering emitting processes, practices, and designs is divided into two basic categories. The first category of energy efficient improvement options includes improvement options or processes that maximize the energy efficiency of the individual emissions unit. The second category of energy efficiency improvements includes options that could reduce emissions is more appropriate for new Greenfield facilities that includes equipment or processes that have the effect of lowering emissions by improving the utilization of thermal energy and electricity that is generated and used on the site.

(1) In the case of combustion turbine energy efficiency processes, practices and designs, one of the current efficient ways of generating electricity from a natural gas fuel source is through a combined-cycle design. For fossil fuel technologies, efficiency ranges from 30 to 50 percent higher heating value (HHV). A typical coal-fired Rankine cycle power plant has a base load efficiency of approximately 30% HHV while a modern F-Class natural gas fired combined-cycle turbine generator operating under optimal conditions has a baseload efficiency of approximately 50% HHV.

The combined-cycle unit operates based on a combination of two thermodynamic cycles: the Brayton and Rankine cycles. The combustion turbine operates on the Brayton cycle while the HRSG and steam turbine operate on the Rankine cycle. The combination of both of these cycles contributes to the higher efficiency of the combined-cycle power plants.

While there are number of modifications to a combustion turbine generator that exist, CEC has identified the following additional processes, practices and designs that are applicable for the combined combustion turbine generator:

(a) *Periodic Burner Tuning*: The modern F-Class combustion turbines have a regularly scheduled maintenance program for optimal efficiency of the turbine. Three basic maintenance levels exist: combustion inspections, hot gas path inspections, and major overhauls with combustion inspections being the most common. As a part of the maintenance activity, combustors are tuned to restore the highly efficient low-emission operation.

(b) *Reduction in Heat Loss:* Use of insulation blankets help minimize heat loss at cooler temperatures, as well as protect personnel and nearby auxiliary equipment, insulation blankets will be deployed around the combustion turbine casing. Uses of the blankets immediately minimize any heat loss from the combustion turbine shell and increase the overall efficiency of the machine.

(c) *Instrumentation and Controls*: Operation of the combustion turbine is all under automatic control via the distributed control system (DCS). DCS oversees all aspects of the operation including fuel feed and burner operations to achieve efficient low-NOx combustion. The control system monitors the operational parameters of the unit and modulates the fuel flow and turbine operations to achieve optimal high-efficiency low-emission performance for full-load and part-load conditions.

CEC proposed the use of a new combined-cycle combustion turbine, which is more energy efficient compared with the emissions from a simple-cycle gas turbine in the following table.

GHG Control Technologies	**Emission Rate (lb CO_2/MWh)**
New combined-cycle gas CTG	774
Existing combined-cycle CTG	824-996
Simple cycle CT	~1,319

CEC has elected to construct the Siemens 501F CTG/HRSG with a CTG rated at 180 MW nominal and a duct burner-fired heat recovery steam generator (HRSG). The maximum design rated capacity of the duct burners will be 475 million British thermal units per hour (MMBtu/hr). The CTG will be fired exclusively with pipeline-quality natural gas and the HRSG will be fired with pipeline quality natural gas, "off" gas from an adjacent refining facility or a combination of the two. The Siemens 501F turbine was chosen for CEC because it has the appropriate size needed for this facility, CEC is already equipped with two (2) operating Siemens 501F turbines, and several Siemens 501F turbines are ready for use at CEC's sister facilities. In comparison with other turbines, EPA has identified the several high energy efficient models commercially available around the 180 MW range. For a CTG, efficiency can be determined by the heat rate, which can be expressed as Btu of the fuel combusted divided by kWh of electricity produced (Btu/kWh). The lower the overall numbers, the less heat needed to produce a unit of electricity. Using data provided by the manufacturer for CTG under ISO test conditions, EPA identified the following models:

Manufacturer	Model	Net Plant Output (kW)[9]	LHV[10] ISO Heat Rate (Btu/kWh)	%Net ISO Plant Efficiency (ISO)
Rolls-Royce	2 x Trent 60 DLE	149	7,129	45.5
Rolls-Royce	2 x Trent 60 WLE ISI	153	7,281	44.5
Mitsubishi	MPCP1 (M501)	167	7,000	46.3
Siemens	SCC6-2000F 1x1 (FD2/FD3)	171	7,007	46.2
Hitachi	206FA	215	6,800	47.7

[9] Net plant output is calculated using specific design (i.e., ISO) test criteria
[10] Lower heat rate is determined by subtracting the heat of vaporization of water from the higher heating value.

As listed in the previous table, the Siemens 501F-series turbine has a calculated efficiency of 46.2% which is a similar efficiency to the other listed natural gas-fired combined-cycle combustion turbines (efficiencies tend to range from 40% to 60% with larger kW-producing turbines typically having the highest efficiencies)[11]. Since age, ambient and operating conditions will affect efficiency, the heat rate numbers presented above are used to compare efficiency between turbine models and do not translate directly into permit limitations.

(2) For the heat recovery steam generator, energy efficient processes, practices and design include:

a. *Heat Exchanger Design*: Heat exchanger design is optimized to provide maximum heat exchange transfer from the waste heat of the combustion turbine exhaust using multiple thin-walled tubes filled with fluid and at the same time minimizing the overall size of the HRSG.

b. *Insulation*: Similar to the combustion turbine practice, use of insulation to minimize heat loss to the surroundings is used to help improve the overall efficiency of the HRSG. Insulation is applied to the HRSG panels that make up the shell of the unit, to the high-temperature steam and water lines, and typically to the bottom portion of the stack.

c. *Minimizing Fouling of Heat Exchange Surfaces*: Since HRSGs are made up of numerous tubes within the shell of the unit are used to generate steam from the combustion turbine, the tubes and their extended surfaces must be kept as clean as possible to maximize heat transfer. Fouling occurs from the constituents within the exhaust gas stream. To minimize fouling, filtration of the inlet air to the combustion turbine is performed. Additionally, cleaning of the tubes is performed during periodic outages.

d. *Minimized Vented Steam and Repair of Steam Leaks*: Routine maintenance checks will include inspection of valves and pipes for steam leaks and reducting steam escaping which would result in large losses in efficiency in power generation.

The HRSG duct burners will be fueled by pipeline-quality natural gas, "off" gas from a nearby refining facility or a combination of the two. The "off" gas from the nearby facility will have a mixture of different fuels but is primarily composed of methane and hydrogen gas. As a measure of energy conservation and efficiency, CEC makes efficient use of the "off" gas from the nearby refining facility because normally the "off" gas would be combusted into the atmosphere as a waste product via flare. A "typical" analytical composition of the "off" gas is listed in the following table:

[11] United States Environmental Protection Agency, Combined Heat and Power Partnership, *Technology Characterization: Steam Turbines*, December 2008, p.8-9
<http://www.epa.gov/chp/documents/catalog_chptech_steam_turbines.pdf>

Formula	Name	Mole %	Molecular Weight (lb/ lb-mol)	HHV (Btu/scf)	Weight %	lb mol carbon/ lb mol component	lb mol C/ lb mol fuel	lb C/ lb fuel
CH_4	Methane	42.23	16.04	1012	36.65	0.7481	0.3159	0.2408
C_2H_6	Ethane	10.41	30.07	1773	15.56	0.7981	0.0831	0.0633
C_3H_8	Propane	2.04	44.09	2524	11.65	0.8165	0.0167	0.0127
C_4H_{10}	n-Butane	0.28	58.12	3271	4.57	0.8259	0.0023	0.0018
i- C_4H_{10}	Isobutane	0.18	58.12	3261	3.47	0.8259	0.0015	0.0011
n-C_5H_{12}	*n*-Pentane	0.03	72.15	4020	1.99	0.8316	0.0002	0.0002
i- C_5H_{12}	Isopentane	0.05	72.15	4011	1.7	0.8316	0.0004	0.0003
C_5H_{12}	Neopentane		72.15	3994	0	0.8316	0.0000	0.0000
C_6H_{14}	*n*-Hexane		86.17	4768	4.72	0.8356	0.0000	0.0000
C_7H_{16}	*n*-Heptane		100.2	5503	0	0.8383	0.0000	0.0000
C_2H_4	Ethylene	2.07	28.05	1604	3.02	0.8556	0.0177	0.0135
C_3H_6	Propylene	0.97	42.08	2340	2.8	0.8555	0.0083	0.0063
C_4H_8	*n*-Butene		56.1	3084	1.25	0.8556	0.0000	0.0000
i- C_4H_8	Isobutene		56.1	3069	0	0.8556	0.0000	0.0000
C_5H_{10}	*n*-Pentene		70.13	3837	0	0.8556	0.0000	0.0000
C_6H_6	Benzene		78.11	3752	0	0.9218	0.0000	0.0000
C_7H_8	Toluene		92.13	4486	0	0.9118	0.0000	0.0000
C_8H_{10}	Xylene		106.16	5230	0	0.9043	0.0000	0.0000
C_2H_2	Acetylene		26.04	1477	0	0.9217	0.0000	0.0000
$C_{10}H_8$	Naphthalene		128.16	5854	0	0.9363	0.0000	0.0000
CH_3OH	Methyl Alcohol		32.04	868	0	0.3745	0.0000	0.0000
C_2H_5OH	Ethyl Alcohol		46.07	1600	0	0.5209	0.0000	0.0000
H_2S	Hydrogen Sulfide	0	34.08	646	0	0.0000	0.0000	0.0000
H_2O	Water Vapor		18.02	0	0	0.0000	0.0000	0.0000
H_2	Hydrogen	31.14	2.02	325	7.45	0.0000	0.0000	0.0000
O_2	Oxygen	0.7	32	0	0	0.0000	0.0000	0.0000
N_2	Nitrogen	9.18	28.01	0	4.2	0.0000	0.0000	0.0000
CO	Carbon Monoxide	0.72	28.01	321	0.88	0.4284	0.0031	0.0024
CO_2	Carbon Dioxide	0.002	44.01	0	0.07	0.2727	0.0000	0.0000
TOTAL		99.99			99.98			
						Total lb C/lb fuel		0.3424
						wt %C for "off" gas		34.24%

The use of "off" gas in the duct burners is variable based on the availability of "off" gas produced by the adjacent refinery and the need for the "off" gas as a fuel at the CEC facility. As a result, it is difficult to estimate how much "off" gas is used in the duct burners on an annual basis and resulting calculated emissions. However, based on the representative sample data presented in the table (previous page), approximately 30% of the "off" gas is hydrogen gas which does not contain any carbon and therefore does not create carbon dioxide as a by-product of combustion. In comparison, pipeline quality natural gas is typically 94% or higher of methane (CH_4) which produces a proportional amount of CO_2. Hence, the overall carbon content and BTU value of "off" gas or any mixture of "off" gas and natural gas will always be lower than pipeline quality natural gas. Therefore, since use of "off" gas will not result in an increase CO_2e emissions compared to combusting only natural gas in the HRSG duct burners. EPA set BACT for the HRSG3 unit assuming 100% natural gas combustion.

(3) Plant-wide energy efficient processes include fuel gas preheating, drain operation, multiple combustion/HRSG trains and boiler feed pump fluid drivers.

a. *Fuel gas preheating*: The overall efficiency is increased with increased fuel inlet temperatures. For the F-class combustion turbine, the fuel gas is heated with high temperature water from the HRSG.

b. *Drain operation*: Drains are required to allow for draining the equipment for maintenance (maintenance drains) and allow condensate to be removed from the steam piping and drains for operation (operation drains) and prevent loss of energy from the cycle.

c. *Multiple combustion turbine/HRSG trains*: Multiple combustion turbine/HRSG trains help with part-load operation and allow for higher overall plant part-load efficiency by shutting down trains operating at less efficiency part-load conditions and ramping up the remaining train(s) to high-efficiency full-load operations.

d. *Boiler feed pump fluid drivers*: Boiler feed pumps are used as a means to impart high pressure on the working fluid. The pumps require considerable power and to minimize the power consumption at part-loads, fluid drives are being used to minimize power consumption at part-load at part-load, improving the facility's overall efficiency.

Step Two: Eliminate Technically Infeasible Control Options

Based on the information reviewed for this BACT analysis, while there are some portions of CCS that are technically infeasible, EPA has determined that overall CCS technology is technologically feasible at this source. Listed below is a summary of those CCS components that are technically feasible and those CCS components that are not technically feasible for CEC.

Step Two Summary for CCS for CEC

CCS Component	CCS Technology	Technical Feasibility
Capture	Post-combustion	Y
	Pre-combustion	N
	Oxy-fuel combustion	N
	Industrial separation (natural gas processing, ammonia production)	N
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 in the United States and currently commercially unavailable.[12]

Step Three: Rank Remaining Control Technologies by Control Effectiveness

The remaining technically feasible options for controlling CO_2 emissions from the combustion turbine operation are as follows (listed in descending order of the most technically feasible):

1) Carbon Capture and Storage (CCS)

CCS could enable large (> 85%) reduction of CO_2 emissions from fossil fuel combustion in power generation, industrial processes and synthetic fuel production[13] and is the best known method of reducing CO_2e emissions into the atmosphere.

2) Inherently lower-emitting processes, practices, and designs which are further subdivided into:
    a. Combustion turbine energy efficiency processes, practices and designs;

[12] U.S. Department of Energy, *Carbon Sequestration Program: Technology Program Plan*, page 20-23
[13] IEA Energy Technology Essentials, "*CO2 Capture and Storage*," December 2006 <http://www.iea.org/techno/essentials1.pdf> (December 2006)

b. Heat recovery steam generator energy efficiency process, practices and designs; and
c. Plant-wide energy efficiency processes, practices, and designs;

To date, other similar facilities with 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/MWh (net) 365-day average, rolling daily for the combustion turbine unit Fugitive methane emissions and SF6 emissions are monitored and maintained using best practice standards.	2011	PSD-TX-1244-GHG
Palmdale Hybrid Power Plant Project Palmdale, CA	combined-cycle combustion turbine and heat recovery steam generator, plus a 50 MW solar array*	Energy Efficiency/ Good Design & Combustion Practices, and use of the solar array	Combustion turbine annual net heat rate limited to 7,319 Btu/kWh (HHV) GHG BACT limit of 0.387 tons CO_2/MWh (net) 365-day average, rolling daily for the combustion turbine unit Auxiliary boiler and heater heat input limit of 110 MMBtu/hr and 500 hours operation on 365-day rolling total SF6 Circuit Breakers BACT limit of 9.56 tpy CO_2e	2011	SE 09-01
Calpine Russell City Energy	600 MW combined-cycle power	Energy Efficiency/ Good Design & Combustion	Combustion turbine Operational limit of 2,038.6 MMBtu/kWh	2011	15487

Hayward, CA	plant	Practices	Fire Pump Diesel Engine GHG BACT limit of 7.6 tpy CO_2e SF6 Circuit Breaker annual limit of 39.3 tpy CO_2e		
PacifiCorp Energy Lakeside, UT	combined-cycle turbine	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine BACT limit of 950 lb CO_2e/MWh	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 (DPEC) Deer Park, TX	180 MW combined-cycle combustion turbine generator and heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine annual net heat rate limited to 7,728 Btu/kWh (HHV) GHG BACT limit of 0.460 tons CO_2/ MWh (net) on 30-day rolling average Annual limit of 1,045,635 tons CO_2e for the FD2 CTG and 1,063,650 CO_2e for the FD3 CTG on a 365-day average, rolling daily Fugitive methane emissions and SF6 emissions are monitored and maintained using best practice standards and Auditory, Visual, and Olfactory (AVO) Monitoring	2012 (currently on Public Notice)	PSD-TX-979-GHG

*Palmdale is unique as the applicant proposed to include, and thus the BACT analysis and eventual limit included, use of a solar component that includes up to 50 MW of potential solar thermal power generation, which represents an inherently lower-emitting technology for that proposed facility.

Step Four: Evaluate Top Control Alternatives - Economic, Energy, and Environmental Impacts

EPA Region 6 reviewed CEC's CCS cost estimate and believes the overall cost estimation is financially prohibitive given the high cost of this GHG control strategy in comparison to the overall cost of the project. CCS costs include installation and operation of carbon capture controls and construction of a new pipeline to transport the CO_2 approximately 15 miles[14] (24 kilometers) to the closest site with recognized potential for geological storage of CO_2, which is the enhanced oil recovery (EOR) operations located at the Hastings oil field, southwest of Houston, Texas.

The bulk of the cost for CCS is attributable to the post-combustion capture and compression system, and the additional operating cost estimates are listed in detail in Table 9 of Statement of Basis Appendix. As it stands, the estimated cost to construct and install a CCS system to the turbine is approximately \$113 million[15], around 50% of the cost of a typical gas-fired combined cycle turbine without CCS. Additionally CEC, using EPA guidance documents, has provided an estimation that the overall average operating costs for the entire CCS system could add approximately \$80 million annually (See Statement of Basis Appendix). While CEC has provided information suggesting that annual operating costs for CCS could increase overall costs by as little as 20%[16], EPA notes that CEC arrives at this figure by including the lowest estimated cost for each and every step of the CCS process. CEC's analysis also included an estimate of the annual operating costs for CCS if the highest costs were needed for each and every step of the CCS process, and estimated the annual operating cost increase to be approximately 58%. Since it is unlikely that either the lowest costs or the highest costs could be achieved for each and every step of the process, EPA has instead relied upon the average costs and determined that the average combined costs of installation and operation of a CCS system still makes CCS economically infeasible for this project.

In addition, EPA notes that implementing CCS would result in energy penalty simply because the CCS process will use energy produced by the plant. This may, in turn, potentially increase the natural gas fuel use of the plant, with resulting increases in emissions of non-GHG pollutants, to overcome these efficiency losses, or would result in less energy being produced for use on the grid. The *Report of the Interagency Task Force on Carbon Capture and Storage* has estimated that an energy penalty of as much as 15% would result from inclusion of CO_2 capture (Reference 4, page A-14) and an overall loss of energy efficiency of approximately 7%[17]. It was concluded in the same report[18] that while CCS is technically feasible at this time, the costs for the capture and compression of CO_2 remains the biggest barrier to widespread commercialization of CCS.

Therefore, CCS has been eliminated as BACT for this particular project based upon research and analysis showing that there is a significant negative economic impact due to the additional projected capital costs of implementing and operating CCS as the control technology at the proposed combustion turbine. In addition, the potential negative environmental and energy impacts of increased non-GHG pollutant emissions, the overall loss in energy efficiency, and/or

[14] University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, <http://www.beg.utexas.edu/gccc/miocene/>

[15] *Natural Gas Combined-Cycle Plants With and Without Carbon Capture & Sequestration*, DOE <http://www.netl.doe.gov/energy-analyses/pubs/deskreference/B_NGCC_051507.pdf>

[16] The minimum cost factor found for implementation/operation of the CO2 capture systems within the cost-related information reviewed for CCS technology was found from the "Properties" section of the Greenhouse Gas Mitigation Strategies Database (last accessed April 2010) (<http:/ghg.ie.unc.edu:8080/GHGMDB/#data>), which was obtained through the EPA GHG web site (<http://www.epa.gov/nsr/ghgpermitting.html>).

[17] IPCC Special Report of the Interagency Task Force on *Carbon Capture and Storage* (August 2010)

[18] Ibid., p. 33-51

decreased energy produced for use on the grid also provide a basis for excluding CCS as BACT for this facility.

Step Five: Select BACT

CEC intends to initially construct and install an FD2-series combustion turbine with plans to modify it within an eighteen (18) month period after commercial operation of the FD-2 series turbine to the FD3-series combustion turbine. The proposed BACT limits are in terms of efficiency measured in units of Btu of fuel energy consumed in order to generate a kilowatt of electric energy (Btu/kWh). Since CCS has been eliminated as BACT for CTG3, then BACT for the new combined-cycle combustion turbine is the high efficiency processes, practices and designs which are made enforceable by output-based and annual BACT limits. The average heat rate in terms of Btu/kWh (HHV) will be the same for the FD2 configuration as the FD3 configuration when in continuous operation, since the FD2-series and FD3-series combustion turbines have the same efficiency. However, the FD3 configuration provides greater output at high ambient temperatures during base load periods. Therefore, for the FD3, the potential annual electric generation (MWh) and fuel usage, as well as corresponding GHG emissions, will be higher on an annual basis, maximum CO_2e potential emissions will increase by only two percent (2%) from 1,045,635 tons for the FD2-series to 1,063,650 tons of CO_2e for the FD3-series combustion turbine (see Statement of Basis Appendix, Tables 1 and 2).

a) Degradation consideration for combined-cycle combustion turbine generator efficiency

To establish an enforceable BACT condition that can be achieved over the life of the facility, it is important that the permit limit accounts for the anticipated degradation of the equipment over time between regular maintenance cycles. A 48,000-operating-hour degradation curve provided by the manufacturer, Siemens, reflects anticipated recoverable and non-recoverable degradation in heat rate between major maintenance overhauls of approximately five percent (5%). The results of the degradation curves differentiate between "recoverable" and "non-recoverable" degradation. Components of the turbine and combustion system subject to high thermal and mechanical stress are designed for periodic refurbishment or replacement. The turbine components most affected by the combustion process include combustion liners, fuel nozzle assemblies, transition pieces, turbine nozzles, stationary shrouds, and turbine buckets. These components are often referred to as "hot gas path" components. "Recoverable" degradation is mostly attributable to turbine blade fouling due to impurities in intake air and fuel. This type of degradation can be mitigated through inspection programs, on-line turbine water washes, instrument calibration, and other maintenance activities. "Non-recoverable" degradation is mainly attributed to blade surface roughness, erosion and blade tip rubs and cannot be restored upon a maintenance overhaul.

The manufacturer's degradation results only account for the anticipated degradation within the first 48,000 hours of the gas turbine's useful life; they do not reflect any potential increase in this rate of degradation which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, the projected 5% degradation rate represents the average, and not the maximum or guaranteed rate of degradation for the turbines. Therefore, CEC proposes that, for the purposes of deriving an enforceable BACT limit on the proposed facility's heat rate, gas turbine degradation may be reasonably be estimated at six percent (6%) of the facility's heat rate.

Finally, in addition to the heat rate degradation from normal wear and tear on the turbines, CEC also suggested a compliance margin based on potential degradation in other elements of the combined-cycle plant that would cause the overall plant heat rate to rise (i.e., cause efficiency to fall). CEC proposed a 3% degradation rate to account for these factors. The other elements of the combined-cycle plant include the following:

- Degradation in Turbine Exhaust Flow: The gas turbine manufacturer's degradation curves predict potential recoverable and non-recoverable degradation in gas turbine exhaust flow over the 48,000-maintenance cycle. This degradation in exhaust flow could result in a direct reduction in the ability of the steam turbine to generate power, which could further degrade the plant's overall efficiency. While degradation in the exhaust flow is expected to be partially offset by degradation in exhaust temperature (which raises over the maintenance cycle), this offset is not expected to make up for anticipated degradation in the reduction in steam turbine power as a result of reduced exhaust flow.

- Degradation in Performance of Steam Turbine and Other Equipment: Degradation in the performance of the heat recovery steam generator, steam turbine, heat transfer, cooling tower, and ancillary equipment such as pumps and motors is also expected to occur over the course of a major maintenance cycle.

b) BACT Limit:

By establishing the energy efficiency for the combined-cycle turbine as BACT, permit conditions must be developed to ensure that CEC installs and operate an energy efficient turbine in an energy efficient manner.

EPA has developed an emission limit in tons of GHG per MWh produced that must be met during the initial and periodic stack testing. Since ambient conditions can affect the efficiency during a stack test and cannot be predicted at this time, the emission limit is being set using International Organization for Standardization (ISO) conditions. ISO 3977-2 is corrected for the following conditions:

- Ambient Dry Bulb Temperature: 59°F
- Ambient Relative Humidity: 60%
- Barometric Pressure: 14.69 psia
- Fuel Lower Heating Value: 20,647 Btu/lb
- Fuel HHV/LHV Ratio: 1.1086

1) BACT Limit for the Combined-Cycle Combustion Turbine Generator

To ensure CEC operates its facility to minimize greenhouse gases, EPA proposes to establish a CO_2 emission limit/MWh. To determine an appropriate heat rate limit for continuous operations, the baseline annual average heat rate (HHV) of 6,852 Btu/kWh is used with the 3.3% design margin taken into account followed by a six percent (6%) performance margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls, and then a three percent (3%) degradation margin reflecting the variability in operation in auxiliary plant equipment due to use over time, resulting in the annual average heat rate (HHV) of 7,728 Btu/kWh (See Statement of Basis Appendix, Table 4). Additionally, to determine the heat input limit for this facility, the heat rate is calculated assuming that all steam generated in the heat recovery steam generator is used to generate electricity in the existing on-site steam turbine even though there are periods when some or all of the generated steam is sold to a neighboring facility rather than sent to the on-site steam turbine.

The proposed GHG PSD permit, if approved, requires an output-based BACT limit of **0.460 tons CO_2/MWh (net) for both the FD2 and FD3 engines** on a 30-day rolling average and an annual GHG BACT limit of **985,340 tons CO_2e per year for the FD2 series engine** and **1,003,355 tons of CO_2e per year for the FD3 series engine** on a 365-day rolling average. This is with the understanding that the FD2 series will be upgraded to the FD3 series within a statutory timeframe of 18 months under the conditions of this permit. In establishing an enforceable BACT limit over the lifetime of the turbine, Calpine accounted for the anticipated degradation of the equipment over time between regular maintenance cycles, as discussed in this section. (See Statement of Basis Appendix, Table 4 for calculations)

c) Operating Conditions

Listed below are the operating conditions and work practices for the heat recovery steam generator and the plant-wide operations that ensure that CTG3 is operating at the highest possible efficiency.

1) HRSG3 Unit Operating Conditions

The Heat Recovery Steam Generator (HRSG3) energy efficiency processes, practices and designs considered include:

i. Energy efficient heat exchanger design. In this design, each pressure level incorporates an economizer section(s), evaporator section, and superheater section(s);

ii. Addition of insulation to the HRSG3 panels, high-temperature steam and water lines and to the bottom portion of the stack;

iii. Filtration of the inlet air to the combustion turbine and periodic cleaning of the tubes (performed at least every 18 months) is performed to minimize fouling; and

iv. Minimization of steam vents and repairs of steam leaks.

2) Plant Wide Operating Conditions

Within the combined-cycle power plant, several plant-wide, overall energy efficiency processes, practices and designs are included as BACT requirements because the additional operating conditions/practices help maintain the efficiency of the turbine. The requirements include:

i. Fuel gas preheating. For the F-class combustion turbine based combined-cycle, the fuel gas is pre-heated to temperature of approximately 300°F with high temperature water from the HRSG;

ii. Drain operation. Operation drains are controlled to minimize the loss of energy from the cycle but closing the drains as soon as the appropriate steam conditions are achieved;

iii. Multiple combustion turbine/HRSG trains. Multiple combustion turbine/HRSH trains help with part-load operation. A higher overall plant part-load efficiency is achieved by shutting down trains operating at less efficient part-load conditions and ramping up the remaining train(s) to high-efficiency full-load operation;

iv. Boiler feed pump fluid drives. To minimize the power consumption at part-loads, the use of fluid drives or variable-frequency drives are used to minimize the power consumption at part-load conditions;

d) BACT Compliance:

For both the FD2 and FD3-series, the combined-cycle combustion turbine unit is designed with a number of features to improve the overall efficiency. The additional combustion turbine design features include:

1. Periodic burner tuning as part of a regularly scheduled maintenance program to help ensure a more reliable operation of the unit and maintain optimal efficiency;

2. Insulation blankets are utilized to minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine; and

3. Air will be used to cool the generators resulting in a lower electrical loss and higher unit efficiency.

Calpine CEC's proposed method to demonstrate compliance with the CO_2 emission limit of 0.460 tons of CO2 per MWh (net)[19] established as BACT by using fuel flow meters to monitor the quantity of fuel combusted in the electric generating unit and performing periodic scheduled fuel sampling pursuant to 40 CFR 75.10(3)(ii) and the procedures listed in 40 CFR 75, Appendix G. Results of the fuel sampling will be used to calculate a site-specific Fc factor, and that factor will be used in the equation below to calculated CO_2 mass emissions. As an alternative, Calpine may determine the CO_2 hourly emission rate and CO_2 mass emissions using an O_2 monitor pursuant to 40 CFR Subpart 75 and Appendix F of 40 CFR Subpart 75. The proposed permit also includes an alternative compliance demonstration method in which Calpine CEC may install, calibrate, and operate a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions. To demonstrate compliance with the CO_2 BACT limit of 0.460 tons of CO_2 per MWh

[19] Output-based limit is based on ton of CO_2 versus ton of CO_2e per megawatt-hour because all emissions determined by compliance monitoring in accordance to 40 CFR Part 75 are done in lbs of CO_2 as opposed to lbs of CO_2e.

(net) using CO_2 CEMS, the measured hourly CO_2 emissions are divided by the net hourly energy output and averaged daily.

Currently, the two existing natural gas-fired turbines at CEC utilize fuel flow meters and monthly GCV (Gross Calorific Value) sampling in order to comply with the Acid Rain quality assurance and monitoring requirements of 40 CFR 75, Appendix D and G. The proposed natural gas-fired turbine identified as CTG3/HRSG3 will also comply with the fuel flow metering and GCV sampling requirements listed in Appendix D. Calpine CEC proposes to determine a site-specific Fc factor using the ultimate analysis and GCV in equation F-7b of 40 CFR 75, Appendix F. The site-specific Fc factor will be re-determined annually in according to 40 CFR 75, Appendix F, §3.3.6.

The equation for estimating CO_2 emissions as specified in 40 CFR 75.10(3)(ii) is as follows:

Where:

W_{CO2} = CO_2 emitted from combustion, tons/hour
MW_{CO2} = molecular weight of CO_2, 44.0 lbs/mole
Fc = Carbon-based Fc-Factor, 1040 scf/MMBtu for natural gas or site-specific Fc factor
H = hourly heat input in MMBtu, as calculated using the procedure in 40 CFR 75, Appendix F, §5
Uf = 1/385 scf CO_2/lb-mole at 14.7 psia and 68°F

CEC is subject to all applicable requirements for fuel flow monitoring and quality assurance pursuant to 40 CFR 75, Appendix D, which includes:

- Fuel flow meter- meets an accuracy of 2.0%, required to be tested once each calendar quarter pursuant to 40 CFR 75, Appendix D, §2.1.5 and §2.1.6(a))
- Gross Calorific Value (GCV)- determine the GCV of pipeline natural gas at least once per calendar month pursuant to 40 CFR 75, Appendix D, §2.3.4.1

If oxygen analyzers are used for compliance, CEC is subject to all applicable requirements for the oxygen analyzers and quality assurance using cylinder gas audits (CGAs) at least quarterly in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.2, with the following exception: a relative accuracy test audit is not required once every four quarters (i.e., two successive semiannual CGAs may be conducted). CEC may comply with the quality assurance provisions of 40 CFR Part 75, Appendix B, in lieu of complying with the provisions of 40 CFR Part 60, Appendix F.

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 (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 365-day average, rolling daily. Emissions from CH_4 and N_2O are very low compared to the emissions from CO_2 which contribute the most (greater than 99%) to the overall emissions from the CTGs, so additional emissions analysis is not required for CH_4 and N_2O. In addition, while an initial stack test demonstration will be required for CO_2 emissions from 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 approximately 0.09% of the total CO_2e emissions from the CTGs and are considered a *de minimis* level in comparison to the CO_2 emissions.

For startup and shutdown operating scenarios for the proposed CTG, BACT will be achieved by minimizing the duration of the start-up and shutdown events, consistent with market demands, and by engaging the pollution control equipment (e.g., the SCR system in combined-cycle) as soon as practicable, based on vendor recommendations and guarantees. During periods of startup and shutdown, the permittee must record the time, date, fuel heat input (HHV) in MMBtu/hr and the duration of each startup and shutdown event. All emissions during startup and shutdown are minimized by limiting the duration of operation. The estimated 70 tons/hour (See Statement of Basis Appendix, Table 5) illustrate that startup and shutdown emissions are lower than "normal" emissions and are accounted for in the Annual Facility Emissions (Statement of Basis Appendix, Table 1). To demonstrate compliance with the startup and shutdown emissions, Calpine shall record the time, date, fuel heat input and duration of each startup and shutdown event. The duration of operation during startup and shutdown are defined as follows:

1. A startup of CTG3 is defined as the period that begins when there is measureable fuel flow to the CTG3 and ends when the CTG3 load reaches 60 percent. A startup for each CTG3 is limited to 480 minutes.
2. A shutdown of each CTG3 is defined as the period that begins when CTG3 load falls below 60 percent and ends when there is no longer measureable fuel flow to CTG3. A shutdown for CTG3 is limited to 180 minutes.

Under draft terms, records of all emission limit calculations and startup and shutdown events shall be kept on-site for a period of 5-years. After review of the submitted materials, EPA agrees with and adopts Calpine's BACT analysis for the natural gas-fired combined-cycle combustion turbines.

X. GHG BACT for the Fugitive Emission Sources (NG-FUG/Fuel Gas Piping)

<u>Step One: Identify All Potentially Available Control Technologies</u>

The control technology for process fugitive emissions of GHGs are:

- Leakless Technology
- Instrument Leak detection and repair (LDAR) programs
- Remote Sensing
- Auditory, Visual, and Olfactory (AVO) Monitoring

<u>Step Two: Eliminate Technically Infeasible Control Options</u>

- *Leakless Technology* – Leakless technology valves may be incorporated in situations where highly toxic or otherwise hazardous materials are present. Likewise, some technologies, such as bellows valves, cannot be repaired without a unit shutdown. Because natural gas is not considered highly toxic nor a hazardous material, this gas does not warrant the risk of unit shutdown for repair, and therefore leakless valve technology for fuel lines is considered technically impracticable.

- *Instrument LDAR Programs* – Is considered technically feasible.
- *Remote Sensing* – Is considered technically feasible.
- *AVO Monitoring* – Is considered technically feasible.

Step Three: Rank Remaining Control Technologies by Control Effectiveness

Instrument LDAR programs and the alternative work practice of remote sensing using an infrared camera have been determined by EPA to equivalent methods of piping fugitive controls.[20] The most stringent LDAR program, 28LAER, provides for 97% control credit for valves, flanges, and connectors.

As-observed AVO methods are generally somewhat less effective than instrument LDAR and remote sensing, since they are not conducted at specific intervals. However, since pipeline natural gas is odorized with very small quantities of mercaptan, as-observed olfactory observation is a very effective method for identifying and correcting leaks in natural gas systems. Due to the pressure and other physical properties of plant fuel gas, as-observed audio and visual observations of potential fugitive leaks are likewise moderately effective.

Step Four: Evaluate Top Control Alternatives

Although instrument LDAR and/or remote sensing of piping fugitive emissions in natural gas lines may be somewhat more effective than as-observed AVO methods, these methods are not economically practicable for GHG control from components in fuel gas service. The incremental GHGs controlled by implementation of the 28LAER or a comparable remote sensing program is less than 156 tons CO_2e per year, or 0.01% of the total project's proposed CO_2e emissions.

Step Five: Select BACT

EPA has reviewed and CEC's Fugitive Emission Sources top-down BACT analysis. Based on the economic impracticability of instrument monitoring and remote sensing for fuel gas piping components, EPA proposes to incorporate as-observed AVO as BACT for the piping components in new combustion turbine generator and heat recovery steam generator and proposes an annual BACT emission limit of **157 tons per year CO_2e**. Calpine also identified and adopted the use of dry compressor seals, use of rod packing for reciprocating compressors, and the use of low-bleed gas-driven pneumatic controllers or air-driven pneumatic controllers as BACT for fugitives. EPA determines that the AVO program for fugitives for control of CH_4 emissions is BACT.

XI. GHG BACT for the SF6 Insulated Electrical Equipment (SF6-FUG)

[20] 73 FR 78199-78219, December 22, 2008.

Step One: Identify All Potentially Available Control Technologies

Several control options can be used to help minimize GHG emissions for the SF6 circuit breakers which include:

- Use of dielectric oil or compressed air circuit breakers – these types of circuit breakers do not contain any GHG pollutants and serve as a substitute for SF6 circuit breakers. Potential alternatives to SF6 circuit breakers are addressed in the National Institute of Standards and Technology (NTIS) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6*[21]

- Totally enclosed SF6 circuit breakers with leak detection system - Modern SF6 circuit breakers, as opposed to the older SF6 circuit breakers, are designed as a totally enclosed-pressure system which reduces the potential for SF6 emissions. These systems are equipped with a density alarm that provides a warning when 10% of the SF6 (by weight) has escaped. This identifies potential leak problems before the bulk of the SF6 can escape

Step Two: Eliminate Technically Infeasible Control Options

At this time, sulfur hexafluoride (SF6)-containing circuit breakers are the only commercially available circuit breakers. While there are other potential dielectric, non-greenhouse gas substances such as oil and air that could be used, these types of circuit breakers are all in the research stage and thus are not technically feasible for use at the CEC.[22]

Step Three: Rank Remaining Control Technologies by Control Effectiveness

The only remaining technically feasible options for insulating electrical equipment associated with the combustion turbine process are totally enclosed SF6 circuit breakers with a leak detection system.

Step Four: Evaluate Top Control Alternatives

There no other control alternatives available at this time as stated in Step 2, therefore SF6 circuit breakers will only be considered.

Step Five: Select BACT

Based on Calpine's top-down BACT analysis for fugitive emissions, Calpine concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection is the appropriate BACT control technology option. The proposed GHG PSD permit, if approved, is comprised of a 72 pound SF_6 insulated circuit breaker. CEC will monitor the SF_6 emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use. The annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD. EPA concurs with and adopts CEC's best work practice standards for control of SF_6 emissions and the state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection for fugitive SF_6 emissions as BACT.

[21] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6*, NIST Technical Note 1425, Nov. 1997, <http://www.epa.gov/electricpower-sf6/documents/new_report_final.pdf>

[22] Christophorous, L.G. et al., pp. 28-29

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, EPA is relying on a Biological Assessment (BA) prepared by the applicant and reviewed by EPA. Further, EPA designated CEC as its non-federal representative for purposes of preparation of the BA and for conducting informal consultation.

A draft BA has identified twelve (12) species as federally endangered or threatened in Harris County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD).

EPA has determined that issuance of the proposed permit to CEC for construction of the combustion turbine generator/heat recovery steam generator will have no effect on five (5) of these listed species, specifically the smalltooth sawfish (*Pristis pectinata*), the red-cockaded woodpecker (*Picoides borealis*), the whooping crane (*Grus americana)*, the Louisiana black bear (*Ursus americanus luteolus*), and the red wolf (*Canis rufus*). These species are either thought to be extirpated from the county or Texas or are not present in the action area.

The remaining seven (7) species identified are species that may be present in the action area in certain circumstances. As a result of this potential occurrence and based on the information provided in the draft BA, the issuance of the permit may affect, but is not likely to adversely affect the following species. As a result, EPA will submit the final draft BA to the Southwest Region, Clear Lake, Texas Ecological Services Field Office of the USFWS for its concurrence that issuance of the permit may affect, but is not likely to adversely affect the following species:

- Houston toad (*Bufo houstonensis*).
- Texas prairie dawn-flower (*Hymenoxys texana*).

EPA will also submit the final draft BA to the NOAA Southeast Regional Office, Protected Resources Division of NMFS for its concurrence that issuance of the permit may affect, but is not likely to adversely affect the following species:

- leatherback sea turtle (*Dermochelys coriacea*)
- green sea turtle (*Chelonia mydas*)
- Kemp's ridley sea turtle (*Lepidochelys kempii*)
- loggerhead sea turtle (*Caretta caretta*)
- West Indian manatee (*Trichechus manatus*)

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on endangered 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. Magnuson-Stevens Act

The 1996 Essential Fish Habitat (EFH) amendments to the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) set forth a mandate for NOAA's National Marine Fisheries Service (NMFS), regional fishery management councils (FMC), and other federal agencies to identify and protect important marine and anadromous fish habitat.

To meet the requirements of the Magnuson-Stevens Act, EPA is relying on an EFH Assessment prepared by the applicant and reviewed by EPA.

Tidally influenced portions of the Buffalo Bayou (Houston Ship Channel) which connects to Upper Galveston Bay are located less than one mile from the project site. These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, and subadult red drum (*Sciaenops ocellatus*), Spanish mackerel (*Scomberomorus maculatus*), pink shrimp (*Penaeus duorarum*), white shrimp (*Penaeus setiferus*) and brown shrimp (*Farfantepenaeus aztecus*). The EFH Amendment information was obtained from the Gulf of Mexico Fishery Management Council (http://www.gulfcouncil.org/).

Based on the information provided in the EFH Assessment, EPA concludes that the proposed PSD permit allowing CEC to construct the combustion turbine generator/heat recovery generator, identified as CTG3/HRSG3, will have no adverse impacts on listed marine and fish habitats.

XIV. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on a cultural resource report prepared by Blanton and Associates, Inc. ("Blanton"), CEC's consultant, submitted on May 4, 2012.

Blanton conducted an a cultural resource review within a 1,000-meter radius area of potential effect (APE) of the construction site which included a review of the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and a pedestrian survey. Based on the information provided in the cultural resources report, no archaeological resources or historic structures were found within the APE. The construction site is located in a modern industrial facility in a highly developed, industrialized zone surrounded by oil and gas refineries.

Upon receipt of the report, 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 tribal requests for participation as a consulting party or comments about the project.

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

EPA will provide a copy of this report to the State Historic Preservation Officer for consultation and concurrence with this determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties.

XV. 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 GHG. 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.

XVI. Conclusion and Proposed Action

Based on the information supplied by CEC, our review of the analyses contained in 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 CEC 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.

Statement of Basis

Appendix

for

Channel Energy Center (CEC), LLC
Greenhouse Gas Prevention of Significant Deterioration
Preconstruction Permit

Permit Number: PSD-TX-955-GHG

Table 1. Annual Facility Emissions

Output-based emissions, in tons per megawatt-hour (tons/MWh) on a 30-day rolling average, and annual emissions, in tons per year (TPY) on a 365-day rolling average basis shall not exceed the following:

Phase 1 of Construction							
Emission Unit	**Description**	**GHG Mass Basis**		**BACT**			
			GHG Potential Emissions (TPY)[2,3]		**Output-based BACT CO_2 Limit[1]**	**Tons per year CO_2e[2,3]**	**Annual BACT Limit (TPY CO_2e[2,3])**
CTG3 (FD2) / HRSG3	CTG3/HRSG3 Annual Emissions	CO_2	984,393	CO_2	0.460 tons/MWh 7,730 Btu/KWh	984,393	**985,340**
		CH_4	18.22	CH_4		383	
		N_2O	1.82	N_2O		565	
NG-FUG / Fuel Gas Piping	Fugitive Natural Gas emissions from piping components & Fuel Gas Piping	CO_2	0.29	CO_2		0.29	**157**
		CH_4[4]	7.44	CH_4[4]		156.23	
SF6-FUG	SF_6 Insulated Electrical Equipment	SF_6	0.00018	SF_6		4.3	**4.3**

1. Compliance with the output-based emission limits (on a per hour basis) is based on a 30-day rolling average.
2. Compliance with the annual emission limits (tons per year) is based on a 365-day rolling average.
3. The tpy emission limits specified in this table are not to be exceeded for this facility and includes emissions only from the facility during normal operations and startup and shutdown activities.
4. Because the emissions from this unit are calculated to be 96% methane (CH_4), the remaining pollutant emission (CO_2) is not presented in the table.
5. Because the emissions from this unit are calculated to be over 99.9% carbon dioxide (CO_2), the remaining pollutant emissions (CH_4 and N_2O) are not presented in the table.

Phase 2 of Construction								
Emission Unit	**Description**	**GHG Mass Basis**		**BACT**				
			GHG Potential Emissions (TPY)[2,3]		**Output-based BACT CO_2 Limit[1]**	**Tons per year CO_2e[2,3]**	**Annual BACT Limit (TPY CO_2e[2,3])**
CTG3 (FD3) / HRSG3	CTG3/HRSG3 Annual Emissions	CO_2	1,002,0391	CO_2	0.460 tons/MWh 7,730 Btu/KWh	1,002,391	**1,003,355**
		CH_4	18.55	CH_4		390	
		N_2O	1.86	N_2O		575	
NG-FUG / Fuel Gas Piping	Fugitive Natural Gas emissions from piping components & Fuel Gas Piping	CO_2	0.29	CO_2		0.29	**157**
		CH_4[4]	7.44	CH_4[4]		156.23	
SF6-FUG	SF_6 Insulated Electrical Equipment	SF_6	0.00018	SF_6		4.3	**4.3**

1. Compliance with the output-based emission limits (on a per hour basis) is based on a 30-day rolling average.
2. Compliance with the annual emission limits (tons per year) is based on a 365-day rolling average.
3. The tpy emission limits specified in this table are not to be exceeded for this facility and includes emissions only from the facility during normal operations and startup and shutdown activities.
4. Because the emissions from this unit are calculated to be 96% methane (CH_4), the remaining pollutant emission (CO_2) is not presented in the table.
5. Because the emissions from this unit are calculated to be over 99.9% carbon dioxide (CO_2), the remaining pollutant emissions (CH_4 and N_2O) are not presented in the table.

Table 2: Annual Emissions for the FD2 Combined-cycle Combustion Turbine and Steam Generator (CTG3/HRSG3) –

Phase 1 of Construction			
Total Heat Input Capacity (MMBtu/yr)[1] = 16,564,300	Greenhouse Gas		
	CO_2	CH_4	N_2O
Emission Factor[2] (kg/MMBtu)		1.00E-03	1.00E-04
Global Warming Potential[3] (GWP)	1	21	310
GHG Potential Emissions[4,5] (tpy)	984,393	18.22	1.82
Total GHG Potential Emissions (tpy)	984,413		
CO_2e[6] (tpy)	984,393	383	565
Total CO_2e[7] (tpy)	985,340		

Methodologies and Assumptions

1 Total Heat Input Capacity was determined from the projected annual firing rate information provided by Calpine and reviewed by the EPA

Operating Mode	Annual Operating Hours (hr/yr)	Turbine Heat Input (MMBtu/hr)	Duct Burner Heat Input (MMBtu/hr)	Total Hourly Heat Input (MMBtu/hr)	Total Annual Heat Input (MMBtu/hr)
Base Load, 70°F Ambient, Avg Duct Burner Firing	6,760	1,827.5	0	1,827.5	12,353,900
Base Load, 90°F Ambient, Peak Duct Burner Firing	1,500	1602.8	475	2,077.8	3,116,700
Base Load, 90°F Ambient, Peak Duct Firing, Power Augmentation	500	1,712.4	475	2,187.4	1,093,700
	8,760				16,564,300

[2] CH4 and N2O GHG factors are based on Table C-2 of 40 CFR 98

[3] Greenhouse Warming Potentials (GWP) are from Table A-1 of 40 CFR Part 98, Subpart A. Mandatory Greenhouse Gas Reporting

[4] CO_2 emissions is based on Equation G-4, Appendix G, 40 CFR Part 75, Appendix G where the yearly emission was calculated instead of hourly

$$W_{CO2} = (Fc \times H \times Uf \times MW_{CO2})/2000$$

where: $WCO_2 = CO_2$ emitted (tons/yr) H = Heat Input (MMBtu/yr) MW_{CO2} = Molecular Weight of CO_2 = 44.0 lbs/mole

Fc = Carbon-base F factor, 1040 scf/MMBtu Uf = 1/385 scf CO_2/lb-mole

[5] Greenhouse Warming Potentials (GWP) are from Table A-1 of 40 CFR Part 98, Subpart A and GHG Potential Emissions (tons/year) = Throughput (MMBtu/yr) x Emission Factor (kg/MMBtu) x (2.2 lbs/kg) x (1 ton/2000 lbs)

[6] CO_2e (tpy) = GHG Potential Emissions x GWP for each pollutant

[7] Total CO_2e (tpy) = (CO_2 Potential Emissions x CO_2 GWP) + CH_4 Potential Emissions x CH_4 GWP) + (N_2O Potential Emissions x N_2O GWP)

Table 3: Annual Emissions for the FD3 Combined-Cycle Combustion Turbine and Steam Generator (CTG3/HRSG3)

Phase 2 of Construction				
Total Heat Input Capacity (MMBtu/yr)[1]	16,867,150	Greenhouse Gas		
		CO_2	CH_4	N_2O
Emission Factor[2] (kg/MMBtu)			1.00E-03	1.00E-04
Global Warming Potential[3] (GWP)		1	21	310
GHG Potential Emissions[5] (tpy)		1,002,391	18.55	1.86
Total GHG Potential Emissions (tpy)		1,002,411		
CO_2e[6] (tpy)		1,002,391	390	575
Total CO_2e[7] (tpy)		1,003,355		

Methodologies and Assumptions

[1] Total Heat Input Capacity was determined from the projected annual firing rate information provided by Calpine and reviewed by the EPA

Operating Mode	Annual Operating Hours (hr/yr)	Turbine Heat Input (MMBtu/hr)	Duct Burner Heat Input (MMBtu/hr)	Total Hourly Heat Input (MMBtu/hr)	Total Annual Heat Input (MMBtu/hr)
Base Load, 70°F Ambient, Avg Duct Burner Firing	6,760	1,873	0	1827.5	12,353,900
Base Load, 90°F Ambient, Peak Duct Burner Firing	1,500	1,752	475	2,226.7	3,340,050
Base Load, 90°F Ambient, Peak Duct Firing, Power Augmentation	500	1,871	475	2,346.4	1,173,200
	8,760				16,867,150

[2] CH_4 and N_2O GHG factors are based on Table C-2 of 40 CFR 98

[3] Greenhouse Warming Potentials (GWP) are from Table A-1 of 40 CFR Part 98, Subpart A. Mandatory Greenhouse Gas Reporting

[4] CO2 emissions is based on Equation G-4, Appendix G, 40 CFR Part 75, Appendix G where the yearly emission was calculated instead of hourly

$$W_{CO2} = (Fc \times H \times Uf \times MW_{CO2})/2000$$

where: W_{CO2} = CO_2 emitted (tons/yr) H = Heat Input (MMBtu/yr) MW_{CO2} = Molecular Weight of CO_2 = 44.0 lbs/mole

Fc = Carbon-base F factor, 1040 scf/MMBtu Uf = 1/385 scf CO2/lb-mole

[5] Greenhouse Warming Potentials (GWP) are from Table A-1 of 40 CFR Part 98, Subpart A and GHG Potential Emissions (tons/year) = Throughput (MMBtu/yr) x Emission Factor (kg/MMBtu) x (2.2 lbs/kg) x (1 ton/2000 lbs)

[6] CO_2e (tpy) = GHG Potential Emissions x GWP for each pollutant

[7] Total CO_2e (tpy) = (CO_2 Potential Emissions x CO_2 GWP) + CH_4 Potential Emissions x CH_4 GWP) + (N_2O Potential Emissions x N_2O GWP)

Table 4: Output-Based BACT Limits for FD2 and FD3 Combined-Cycle Combustion Turbine and Steam Generator (CTG3/HRSG3)

Base Net Heat Rate in Btu/kWh (HHV) (without duct firing)	6,852.0	
		+3.30% Design Margin
Heat Rate due to Design Margin (Btu/kWh (HHV)[1]	7,078.1	
		+6.00% Performance Margin
Heat Rate due to Performance Margin and Design Margin (Btu/kWh (HHV))	7,502.8	
		+3.00% Degradation Margin
Calculated Base Net Heat Rate with Compliance Margins (Btu/kWh (HHV))	**7,727.9**	

Calculation of Output-Based BACT Limit (ton CO_2/MWh) for CTG3/HRSG3[5]

EPN	Base Heat Rate (Btu/kWh)[6]	Heat Input Required to Produce 1 MW (MMBtu/h)[2]	tons CO2e per year[3]	Total Heat Input Capacity (MMBtu/yr)[3]	tons CO_2e/MWh[4]
CTG3/ HRSG3	7727.9	7.73	1,063,650	17,880,750	**0.460**

[1]Base Heat Rate was calculated accounting for a 3.3% margin of error in design and construction of the new turbine

[2]Heat Input was calculated by dividing the Base Heat Rate by a factor of 1000

[3]Values obtained from Table 2 for the FD2 series and Table 3 for the FD3 series of the SOB Appendix
[4]tons CO_2e/MWh = ((tons CO_2e per year)/(total heat input capacity/Heat Input Required to produce 1 MW)). [1] Output-based limits will be based on ton of CO_2 versus ton of CO_2e because all emissions determined by monitoring methodology in accordance to 40 CFR Part 75 are done in lbs of CO_2 as opposed to lbs of CO_2e.

[5]Ongoing Output-based BACT limit averaged over each 30-day consecutive period
[6]Base Heat Rate was calculated accounting for 3.3% design margin, 6.0% performance margin and a 3.0% degradation margin (See SOB, Step 5 discussion of GHG BACT for the Combined-cycle Combustion Turbine Generator)

Table 5. Startup and Shutdown Emissions

Total Heat Input Capacity (MMBtu/yr)[1]	1,164

	Greenhouse Gas		
	CO_2	CH_4	N_2O
Emission Factor[2] (kg/MMBtu)		1.00E-03	1.00E-04
Global Warming Potential[3] (GWP)	1	21	310
GHG Potential Emissions[4,5] (tons per hour)	69	1.28E-03	1.28E-04
Total GHG Potential Emissions (tons per hour)	69		
CO_2e[6] (tons per hour)	69	2.69E-02	3.97E-02
Total CO_2e[6] (tons per hour)	69		

Methodologies and Assumptions

[1] Total Heat Input Capacity was determined from the hourly firing rate information provided by Calpine and reviewed by the EPA

	Operating Mode	Turbine Heat Input (MMBtu/hr)	Duct Burner Heat Input (MMBtu/hr)	Total Hourly Heat Input (MMBtu/hr)
Maximum Hourly Heat Input	Base Load, 20°F Ambient, Max Duct Burner Firing	2,017	452	2,469
Maximum Hourly Heat Input during Startup	Base Load, 90°F Ambient, Peak Duct Burner Firing	1,164	0	1,164

[2] CH4 and N2O GHG factors are based on Table C-2 of 40 CFR 98

[3] Greenhouse Warming Potentials (GWP) are from Table A-1 of 40 CFR Part 98, Subpart A. Mandatory Greenhouse Gas Reporting

[4] CO_2 emissions is based on Equation G-4, Appendix G, 40 CFR Part 75, Appendix G where the yearly emission was calculated instead of hourly

$$W_{CO2} = (Fc \times H \times Uf \times MW_{CO2})/2000$$

where: W_{CO2} = CO_2 emitted (tons/yr) H = Heat Input (MMBtu/yr) MW_{CO2} = Molecular Weight of CO_2 = 44.0 lbs/mole
Fc = Carbon-base F factor, 1040 scf/MMBtu
Uf = 1/385 scf CO2/lb-mole

[5] Greenhouse Warming Potentials (GWP) are from Table A-1 of 40 CFR Part 98, Subpart A and GHG Potential Emissions (tons/year) = Throughput (MMBtu/yr) x Emission Factor (kg/MMBtu) x (2.2 lbs/kg) x (1 ton/2000 lbs)

[6] CO_2e (tpy) = GHG Potential Emissions x GWP for each pollutant

[7] Total CO_2e (tpy) = (CO_2 Potential Emissions x CO_2 GWP) + CH_4 Potential Emissions x CH_4 GWP) + (N_2O Potential Emissions x N_2O GWP)

Table 6. Fugitive Emissions (Valves)

	Source Types	Fluid State	Count	Emission Factor[1] (scf/hr/comp)	Greenhouse Gas	
					CO_2[2]	CH_4[3]
NG-FUG	Valves	Gas/vapor	60	0.123	0.05	1.27
	Flanges	Gas/vapor	240	0.017	0.03	0.70
	Relief Valves	Gas/vapor	8	0.196	0.01	0.27
	Sampling Collections	Gas/vapor	18	0. 123	0.01	0.38
Fuel Gas Piping	Valves	Gas/vapor	148	0.123	0.12	3.13
	Flanges	Gas/vapor	162	0.017	0.03	0.47
	Relief Valves	Gas/vapor	0	0.196	0.00	0.00
	Sampling Collections	Gas/vapor	58	0.123	0.05	1.22
Global Warming Potential[3] (GWP)					1	21
GHG Potential Emissions[4] (tpy)					0.29	7.44
Total GHG Potential Emissions (tpy)					7.73	
CO_2e[5] (tpy)					0.29	156.23
Annual CO_2e BACT Limit (tpy)					157	

Methodologies and Assumptions

[1] Emission factors from Table W-1A of 40 CFR 98 Mandatory Greenhouse Gas Reporting

[2] CO_2 emissions based on vol% of CO_2 in natural gas (1.33% from Natural Gas Analysis)

[3] CH_4 emissions based on vol% of CH_4 in natural gas (94.44% from natural gas analysis)

[4] Greenhouse Warming Potentials (GWP) are from Table A-1 of 40 CFR Part 98, Subpart A

[5] CO_2e (tpy) = GHG Potential Emissions x GWP for each pollutant

[6] Total CO_2e (tpy) = (CO_2 Potential Emissions x CO_2 GWP) + CH_4 Potential Emissions x CH_4 GWP) + (N_2O Potential Emissions x N_2O GWP)

sample calc

		%CO_2				
60 valves	0.123 scf	0.0133	lb-mole	44.01 lb CO_2	8760 hr	ton
	hr*valve		385.5 scf	lb-mole	yr	2000 lb

Table 7. Miscellaneous Fugitive Emissions from Small Equipment & Component Repair/Replacement

	Initial Conditions			Final conditions			CO_2[3]	CH_4[4]	
Location	Volume[1] (ft)	Pressure (psig)	Temp (°F)	Pressure (psig)	Temp (°F)	Volume[2] (scf)	Annual (tpy)	Annual (tpy)	Total (tpy)
Turbine Fuel Line Shutdown/Maintenance	955	50	50	0	68	4397	0.0033	0.0861	
Small Equipment/Fugitive Component Repair/Replacement	6.7	50	50	0	68	31	0.00002	0.0006	
Total GHG Potential Emissions							0.0034	0.0867	0.0901
Global Warming Potential							1	21	
CO_2e Emissions							0.0034	1.8216	1.8250

1. Initial volume was calculated by multiplying the cross sectional area by the length of the pipe using the following formula: $V_i = \{\pi * [(\text{diameter(inches)}/12)/2]^2 * \text{length(ft)}\}$

2. Final volume was calculated using ideal gas law: $[((PV)/(ZT))_i = ((PV)/(ZT))_f]$. $V_f = [V_i*(P_i/P_f)*(T_f/T_i)*(Z_f/Z_i)]$, where the compressibility factor, Z, is estimated as the following equation:
$$Z_n = 0.9994 - 0.0002P_n + 3e\text{-}08P_n^2$$

3. CO_2 emissions is based on % volume of CO_2 in Natural gas = 1.33% from natural gas analysis

4. CH_4 emissions is based on % volume of CH_4 in natural gas = 94.4% from natural gas analysis

5. Global Warming Potential factors are based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting

Example Calculation:

$$\frac{4{,}397 \text{ scf Nat Gas}}{\text{year}} \left| \frac{0.0133 \text{ scf } CO_2}{\text{scf Nat Gas}} \right| \frac{\text{lbmole}}{385.5 \text{ scf}} \left| \frac{44.01 \text{ lb } CO_2}{\text{lbmole}} \right| \frac{\text{ton}}{2000 \text{ lb}} = 0.0033 \frac{\text{tons } CO_2}{\text{yr}}$$

Table 8. Fugitive Emissions from Electrical Equipment Insulated with SF_6

Assumptions:	New insulated circuit breaker SF6 capacity	72	lbs
	Estimated annual SF6 leak rate	0.50%	weight
	Estimated annual SF6 mass emission rate	0.00018	tons/year
	Global Warming Potential	23,900	
	Estimated annual CO_2e emission rate	4.302	ton/year

1. Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting

2. Estimated annual CO2e emissions was calculated using the following equation:

$$\frac{72 \text{ lbs}}{} \left| \frac{0.005 \text{ (\%weight)}}{\text{year}} \right| \frac{\text{ton}}{2000 \text{ lbs}} \left| \frac{\text{(GWP) } 23{,}900}{} \right. = \begin{array}{c}4.3\\ \text{Tons/year}\end{array}$$

Table 9. Financial Assessment for Implementation of a Carbon Capture and Storage System at the Calpine CEC Facility

Carbon Capture and Storage (CCS) Components	Annual System CO_2 Throughput (tons of CO_2 captured, transported, and stored)	Pipeline Length for CO_2 Transport System (km)[5]	Range of Approximate Annual Costs for CCS System (in USD)[6]
Post-Combustion CO2 Capture and Compression System[1]			
Average Cost[2,3,4]	956,349		$70,544,632
CO2 Transport System			
Average Cost[2,3,4]	956,349	24	$419,123
CO2 Storage System			
Average Cost[2,3,4]	956,349		$8,918,776
Total Annual Costs for CO2 Capture, Transport and Storage Systems			
Average Cost[2,3,4]	956,349		$79,882,531

Assumptions:

1. Assume that the capture systems is able to capture 90% of the total CO2 emissions generated by the power plant's gas turbines
2. The minimum cost factor found for implementation/operation of the CO2 capture systems within the cost-related information reviewed for CCS technology is found from the "Properties" section of the Greenhouse Gas Mitigation Strategies Database (last accessed April 2010) (http://ghg.ie.unc.edu:8080/GHGMDB/#data), which was obtained through the EPA GHG web site (http://www.epa.gov/nsr/ghgpermitting.html). The factor is based on the increased cost of electricity (COE; in $/MW-h) resulting from the implementation and operation at a CO2 capture system on a natural gas-fired combined-cycle power plant. The factor accounts for annualized capital costs, fixed operating costs, variable operating costs, and fuel costs.
3. Maximum costs are from the Report of the Interagency Task Force on Carbon Capture and Storage, pp 33, 34, 37 and 44 (August 2010) (http://www.epa.gov/climatechange/policy/ccs_task_force.html). The factors from the report are in dollars (USD) per tonne of CO2 processed, transported or stored and have been converted to dollars per ton. Per the report, the factors are based on the increased cost of electricity (COE; in $/kW-h) of an "energy-generating system, including all the costs over its lifetime; initial investment, operations, and maintenance, cost of fuel and cost of capital."
4. The average costs factors were calculated as the arithmetic mean of the minimum and maximum factors for each of the CCS component system and for all
5. The length of the pipeline was the assumed distance to the closest potential geologic storage site, as identified by the University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, available at <http://www.beg.utexas.edu/gccc/miocene/>.
6. Cost estimates (for geologic storage of CO2) are limited to capital and operational costs, and do not include potential costs associated with long-term liability from Intergovernmental Panel on Climate Change (IPCC) Special Report, *Carbon Dioxide Capture and Storage* (New York: Cambridge University Press, 2005). p.44 <http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf>

9111 Jollyville Road | Suite 255 | Austin, TX 78759 | P (512) 349-5800 | F (512) 233-0803
trinityconsultants.com

Trinity Consultants

January 22, 2013

Mr. Jeff Robinson
Permit Section Chief
U.S. Environmental Protection Agency, (6PD-R)
1445 Ross Ave
Dallas, TX 75202-2733

RE: *Application for Prevention of Significant Deterioration for Greenhouse Gas Emissions*
Delaware Basin JV Gathering LLC, Avalon Mega CGF
Loving County, Texas
Customer Number (CN): 603815879, Regulated Entity Number (RN): TBD

Dear Mr. Robinson:

Delaware Basin JV Gathering LLC (DBJVG) proposes to construct a gas processing facility near Mentone in Loving County, Texas (Avalon Mega Central Gathering Facility [CGF]). The primary Standard Industrial Classification code of the proposed Avalon Mega CGF is 1321 (Natural Gas Liquids). DBJVG is registered under Texas Commission on Environmental Quality (TCEQ) Customer Reference Number CN603815879. The Avalon Mega CGF has not yet been assigned a TCEQ Regulated Entity Number (RN).

The proposed Avalon Mega CGF will be a new major source with respect to greenhouse gas (GHG) emissions and subject to Prevention of Significant Deterioration (PSD) permitting requirements. With a final action published in May 2011, EPA promulgated a Federal Implementation Plan (FIP) to implement the permitting requirements for GHGs in Texas, and EPA assumed the role of permitting authority for Texas GHG permit applications with that action. Therefore, GHG emissions from the proposed facility are subject to the jurisdiction of the EPA under authority EPA has asserted in Texas through its FIP for the regulation of GHGs. As shown in the enclosed permit application, the proposed Avalon Mega CGF will be a new major source with respect to nitrogen oxides (NO_x) and carbon monoxide (CO). The project will also trigger PSD review based on significant emission rates for volatile organic compounds (VOC), sulfur dioxide (SO_2), particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), and particulate matter with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$). Therefore, a separate PSD application for all non-GHG pollutants is being submitted to the TCEQ under a separate cover.

If you have any questions or comments about the information presented in this letter, please do not hesitate to call me at (512) 349-5800 or Mr. JD Holt, DBJVG, at (832) 636-2721.

Sincerely,

TRINITY CONSULTANTS

Melissa Dakas

Melissa Dakas
Managing Consultant

Attachments

cc: Air Permits Initial Review Team (APIRT), TCEQ Austin
Ms. Lorinda Gardner, TCEQ Region 7 Midland
Mr. Charles Griffie, Delaware Basin JV Gathering LLC
Mr. Jason Zapalac, Delaware Basin JV Gathering LLC
Mr. JD Holt, Delaware Basin JV Gathering LLC

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION FOR GREENHOUSE GASES

Delaware Basin JV Gathering LLC> Avalon Mega CGF

Prepared By:

Jason Zapalac, Delaware Basin JV Gathering LLC
JD Holt, Delaware Basin JV Gathering LLC

DELAWARE BASIN JV GATHERING LLC
1201 Lake Robbins Drive
The Woodlands, TX 77380
(832) 636-4911
Fax: (832) 636-5446

Melissa Dakas – Managing Consultant

TRINITY CONSULTANTS
12770 Merit Drive
Suite 900
Dallas, TX 75251
(972) 661-8100

Project 124401.0095

Trinity Consultants

Environmental solutions delivered uncommonly well

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1. EXECUTIVE SUMMARY

Delaware Basin JV Gathering LLC (DBJVG) is proposing to construct a gas processing facility near Mentone in Loving County, TX (Avalon Mega Central Gathering Facility [CGF]). The primary Standard Industrial Classification code of the proposed Avalon Mega CGF is 1321 (Natural Gas Liquids). DBJVG is registered under Texas Commission on Environmental Quality (TCEQ) Customer Reference Number CN603815879. The Avalon Mega CGF has not yet been assigned a TCEQ Regulated Entity Number (RN).

Loving County is currently designated as being attainment/unclassifiable for all criteria pollutants. Air emissions from the Avalon Mega CGF project are subject to the jurisdiction of both the U.S. Environmental Protection Agency (EPA) and the TCEQ. Greenhouse Gas (GHG) emissions from the Avalon Mega CGF are subject to the jurisdiction of the EPA under authority asserted in Texas through its Federal Implementation Plan (FIP) for the regulation of GHGs. All non-GHG emissions are subject to the jurisdiction of the TCEQ. Accordingly, DBJVG is submitting applications to both agencies to obtain the requisite authorizations to construct.

1.1. PROPOSED PROJECT

The Avalon Mega CGF will be designed to treat up to 200 million standard cubic feet per day (MMscfd) of sweet natural gas in six (6) identical processing trains. The Avalon Mega CGF will consist of inlet separation facilities, amine treating units, glycol dehydration units, thermal oxidizers, and supporting equipment. The main processes at the Avalon Mega CGF will include the following:

- Inlet separation to separate liquids from the inlet gas
- Removal of carbon dioxide (CO_2) from natural gas through amine treating
- Removal of water from natural gas through glycol dehydration
- Compression of natural gas by natural gas fired compressors
- Pipeline loading of high-pressure condensate liquids
- Truck loading of low-pressure condensate and produced water liquids

The proposed Avalon Mega CGF will include the following emissions sources:

- Amine Units (6)
- Triethylene glycol (TEG) Dehydrators (6)
- Compressor Engines (12)
- Diesel Emergency Power Generators (6)
- Thermal Oxidizers (6)
- Process Flares (3)
- Truck Loading Operations
- Produced Water Tanks (6)
- Planned Maintenance, Start-up, and Shutdown (MSS) activities
- Equipment Leak Fugitives

1.2. PERMITTING CONSIDERATIONS

The DBJVG Avalon Mega CGF site is located in Loving County, Texas. Loving County is currently classified as being attainment/unclassified for all criteria pollutants.[1] Based on the current classification, the Prevention of Significant Deterioration (PSD) regulations define a stationary source as a major source if it emits or has the potential to emit (PTE) either of the following:

- 250 tons per year (tpy) or more of any PSD pollutant; <u>or</u>
- 100 tpy or more of any PSD pollutant if the facility belongs to one of the 28 listed PSD major facility categories.

The natural gas production facility does not belong to one of the 28 listed PSD sources categories; therefore the major source threshold is 250 tons per year (tpy) or more of any criteria PSD pollutant. The Avalon Mega CGF will be a major source (greater than 250 tpy) with respect to nitrogen oxides (NO_x) and carbon monoxide (CO). According to EPA's "major for one, major for all" PSD policy, if a site is major for a regulated pollutant or GHGs, then the remaining regulated pollutants need to be compared to the Significant Emission Rates (SERs; i.e., 40 tpy for NO_x, sulfur dioxide (SO_2), and volatile organic compounds (VOC), 100 tpy for CO, 25 tpy for particulate matter (PM), 15 tpy for particulate matter with an aerodynamic diameter of 10 microns or less [PM_{10}], and 10 tpy for particulate matter with an aerodynamic diameter of 2.5 microns or less [$PM_{2.5}$]) when determining PSD applicability for these pollutants. Based on the potential to emit calculations, the project will also trigger PSD review based on significant emission rates for VOC, SO_2, PM_{10}, and $PM_{2.5}$. In the Tailoring Rule[2], the U.S Environmental Protection Agency (EPA) established a major source threshold of 100,000 tons per year (tpy) of Carbon Dioxide equivalent (CO_2e) emissions and an SER of 75,000 tpy for emissions of Greenhouse Gases (GHG). DBJVG has determined that the GHG emissions from the proposed project will exceed the major source threshold. Therefore, the proposed action represents a new major NSR project with respect to GHG emissions and the aforementioned criteria pollutants.

With the final action published in May 2011, EPA promulgated a Federal Implementation Plan (FIP) to implement the permitting requirements for GHGs in Texas, and EPA assumed the role of permitting authority for Texas GHG permit applications.[3] Therefore, GHG emissions from the proposed facility are subject to the jurisdiction of the EPA under authority asserted in Texas through its FIP for the regulation of GHGs. Accordingly, DBJVG is submitting applications to both EPA and TCEQ to obtain the requisite authorizations to construct.

1.3. PERMIT APPLICATION

All required supporting documentation for the permit application is provided in the following sections. This application includes a TCEQ Form PI-1, other applicable TCEQ forms, a Best Available Control Technology (BACT) evaluation, emissions calculations, process description and flow diagram, and supporting documentation. The Biological Assessment, Cultural Resources, and National Historic Preservation Act Analysis Reports will be submitted under a separate cover.

---

[1] Per 40 CFR §81.344 (Effective April 5, 2005).
[2] Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514 (June 3, 2010).

[3] Determinations Concerning Need for Error Correction, Partial Approval and Partial Disapproval, and Federal Implementation Plan Regarding Texas's Prevention of Significant Deterioration Program, 76 Fed. Reg. 25,178 (May 3, 2011).

2. TCEQ FORM PI-1

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

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

I. **Applicant Information**		
A. Company or Other Legal Name: Delaware Basin JV Gathering LLC		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: Charles Griffie		
Title: Operations Manager		
Mailing Address: 1201 Lake Robbins Drive		
City: The Woodlands	State: TX	ZIP Code: 77380
Telephone No.: (832) 636-1000	Fax No.: (832) 636-5446	E-mail Address: Charles.Griffie@anadarko.com
C. Technical Contact Name: JD Holt		
Title: Sr. Staff EHS Representative		
Company Name: Delaware Basin JV Gathering LLC		
Mailing Address: 1201 Lake Robbins Drive		
City: The Woodlands	State: TX	ZIP Code: 77380
Telephone No.: (832) 636-2721	Fax No.: (832) 636-8042	E-mail Address: JD.Holt@anadarko.com
D. Site Name: Avalon Mega CGF		
E. Area Name/Type of Facility: Gas Processing Facility		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Natural Gas Liquids		
Principal Standard Industrial Classification Code (SIC): 1311		
Principal North American Industry Classification System (NAICS): 211111		
G. Projected Start of Construction Date: 11/25/2013		
Projected Start of Operation Date: 8/1/2014		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: From the intersection of Hwy 302 and Loving County Road 300 in Mentone, Texas, travel north 14 miles on Co Rd 300. Turn left(west) on lease road and travel approx. 1 mile		
City/Town: Mentone	County: Loving	ZIP Code: 79754
Latitude (nearest second): 31° 54' 7.97" N	Longitude (nearest second): 103° 42' 52.17" W	

Texas Commission on Environmental Quality
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I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility):	
J. Core Data Form	
Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L).	☒ YES ☐ NO
K. Customer Reference Number (CN): CN603815879	
L. Regulated Entity Number (RN): TBD	
II. General Information	
A. Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.	☐ YES ☒ NO
B. Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES ☒ NO
C. Number of New Jobs: 20	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: Carlos . resti	District No.: 19
State Representative: Pete P. Gallego	District No.: 74
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested.	
☒ Initial ☐ Amendment ☐ Revision (30 TAC 116.116(e) ☐ Change of Location ☐ Relocation	
B. Permit Number (if existing):	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)*	
☒ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit	
☒ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source	
☐ Other:	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

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

III. Type of Permit Action Requested *(continued)*	
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***	
☐ GOP Issued	☐ GOP application/revision application submitted or under APD review
☐ SOP Issued	☐ SOP application/revision application submitted or under APD review

IV. Public Notice Applicability	
A. Is this a new permit application or a change of location application?	☒ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☐ YES ☒ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☒ YES ☐ NO
If Yes, list the affected state(s) and/or Class I Area(s).	
List: Carlsbad Caverns National Park	
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.	
1. Is there any change in character of emissions in this application?	☐ YES ☐ NO
2. Is there a new air contaminant in this application?	☐ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
F. List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***	
Volatile Organic Compounds (VOC):	
Sulfur Dioxide (SO_2):	
Carbon Monoxide (CO):	
Nitrogen Oxides (NO_x):	
Particulate Matter (PM):	
PM 10 microns or less (PM_{10}):	
PM 2.5 microns or less ($PM_{2.5}$):	
Lead (Pb):	
Hazardous Air Pollutants (HAPs):	
Other speciated air contaminants not listed above: Greenhouse Gases - See Appendix C of Permit Application	

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V. Public Notice Information *(complete if applicable)*		
A. Public Notice Contact Name: JD Holt		
Title: Sr Staff EHS Representative		
Mailing Address: 1201 Lake Robbins Drive		
City: The Woodlands	State: TX	ZIP Code: 77380
B. Name of the Public Place: Loving County Courthouse		
Physical Address *(No P.O. Boxes)*: 100 Bell Street		
City: Mentone	County: Loving	ZIP Code: 79754
The public place has granted authorization to place the application for public viewing and copying.		☒ YES ☐ NO
The public place has internet access available for the public.		☐ YES ☒ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable: Skeet Lee Jones		
Mailing Address: 100 Bell Street		
City: Mentone	State: TX	ZIP Code: 79754
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located.		
Chief Executive: Skeet Lee Jones		
Mailing Address: 100 Bell Street		
City: Mentone	State: TX	ZIP Code: 79754
Name of the Indian Governing Body:		
Mailing Address:		
City:	State:	ZIP Code:

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V.	**Public Notice Information *(complete if applicable) (continued)***	
C.	Concrete Batch Plants, PSD, and Nonattainment Permits	
3.	Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. *(continued)*	
Name of the Federal Land Manager(s):		
D.	Bilingual Notice	
Is a bilingual program required by the Texas Education Code in the School District?		☐ YES ☒ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?		☐ YES ☒ NO
If Yes, list which languages are required by the bilingual program?		
VI.	**Small Business Classification *(Required)***	
A.	Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?	☐ YES ☒ NO
B.	Is the site a major stationary source for federal air quality permitting?	☒ YES ☐ NO
C.	Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☒ YES ☐ NO
D.	Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☐ YES ☒ NO
VII.	**Technical Information**	
A.	The following information must be submitted with your Form PI-1 ***(this is just a checklist to make sure you have included everything)***	
1.	☒ Current Area Map	
2.	☒ Plot Plan	
3.	☐ Existing Authorizations	
4.	☒ Process Flow Diagram	
5.	☒ Process Description	
6.	☒ Maximum Emissions Data and Calculations	
7.	☒ Air Permit Application Tables	
a.	☒ Table 1(a) (Form 10153) entitled, Emission Point Summary	
b.	☒ Table 2 (Form 10155) entitled, Material Balance	
c.	☒ Other equipment, process or control device tables	
B.	Are any schools located within 3,000 feet of this facility?	☐ YES ☒ NO

VII.	Technical Information			
C.	Maximum Operating Schedule:			
Hour(s): 24	Day(s): 365	Week(s): 52	Year(s): 1	
Seasonal Operation? If Yes, please describe in the space provide below.				☐ YES ☒ NO
D.	Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.				
E.	Does this application involve any air contaminants for which a disaster review is required?			☐ YES ☒ NO
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?			☐ YES ☒ NO
VIII.	**State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*			
A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?			☒ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?			☒ YES ☐ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?			☒ YES ☐ NO
D.	Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?			☒ YES ☐ NO
IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*			
A.	Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?			☒ YES ☐ NO
B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?			☐ YES ☒ NO

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts, show how requirements are met; and include compliance demonstrations.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
Is the estimated capital cost of the project greater than $2 million dollars?		☒ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.		
XI.	**Permit Fee Information**	
Check, Money Order, Transaction Number ,ePay Voucher Number:		Fee Amount: $ 75,000
Paid online?		☐ YES ☒ NO
Company name on check: WGR Asset Holding Company		
Is a copy of the check or money order attached to the original submittal of this application?		☒ YES ☐ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?		☒ YES ☐ NO ☐ N/A

Texas Commission on Environmental Quality
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XII. Delinquent Fees and Penalties
This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.

XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: Charles Griffie
Signature: Charles Griffie *Original Signature Required*
Date: 12/10/2012

PRINT FORM RESET FORM

3. CORE DATA FORM

TCEQ Use Only

TCEQ Core Data Form

For detailed instructions regarding completion of this form, please read the Core Data Form Instructions or call 512-239-5175.

SECTION I: General Information

1. Reason for Submission *(If other is checked please describe in space provided)*

☒ New Permit, Registration or Authorization *(Core Data Form should be submitted with the program application)*

☐ Renewal *(Core Data Form should be submitted with the renewal form)* ☐ Other

2. Attachments ☒Yes ☐No

Describe Any Attachments: *(ex. Title V Application, Waste Transporter Application, etc.)* Permit Application

3. Customer Reference Number *(if issued)*: CN 603815879

Follow this link to search for CN or RN numbers in Central Registry**

4. Regulated Entity Reference Number *(if issued)*: RN

SECTION II: Customer Information

5. Effective Date for Customer Information Updates (mm/dd/yyyy)

6. Customer Role (Proposed or Actual) – *as it relates to the Regulated Entity listed on this form. Please check only one of the following:*

☐ Owner ☐ Operator ☒ Owner & Operator
☐ Occupational Licensee ☐ Responsible Party ☐ Voluntary Cleanup Applicant ☐ Other:

7. General Customer Information

☐ New Customer ☐ Update to Customer Information ☐ Change in Regulated Entity Ownership
☐ Change in Legal Name (Verifiable with the Texas Secretary of State) ☒ No Change**

*****If "No Change" and Section I is complete, skip to Section III – Regulated Entity Information.***

8. Type of Customer:	☐ Corporation	☐ Individual	☐ Sole Proprietorship- D.B.A
☐ City Government	☐ County Government	☐ Federal Government	☐ State Government
☐ Other Government	☐ General Partnership	☐ Limited Partnership	☐ Other:

9. Customer Legal Name *(If an individual, print last name first: ex: Doe, John)* — *If new Customer, enter previous Customer below* — *End Date:*

10. Mailing Address:

City | State | ZIP | ZIP + 4

11. Country Mailing Information *(if outside USA)*

12. E-Mail Address *(if applicable)*

13. Telephone Number ( ) -

14. Extension or Code

15. Fax Number *(if applicable)* ( ) -

16. Federal Tax ID *(9 digits)*

17. TX State Franchise Tax ID *(11 digits)*

18. DUNS Number *(if applicable)*

19. TX SOS Filing Number *(if applicable)*

20. Number of Employees

☐ 0-20 ☐ 21-100 ☐ 101-250 ☐ 251-500 ☐ 501 and higher

21. Independently Owned and Operated? ☐ Yes ☐ No

SECTION III: Regulated Entity Information

22. General Regulated Entity Information *(If 'New Regulated Entity' is selected below this form should be accompanied by a permit application)*

☒ New Regulated Entity ☐ Update to Regulated Entity Name ☐ Update to Regulated Entity Information ☐ No Change** *(See below)*

****If "NO CHANGE" is checked and Section I is complete, skip to Section IV, Preparer Information.**

23. Regulated Entity Name *(name of the site where the regulated action is taking place)*

Avalon Mega CGF

24. Street Address of the Regulated Entity: *(No P.O. Boxes)*							
	City		State		ZIP		ZIP + 4
25. Mailing Address:	1201 Lake Robbins Drive Tower						
	City	The Woodlands	State	TX	ZIP	77380	ZIP + 4

26. E-Mail Address:	JD.Holt@anadarko.com

27. Telephone Number	28. Extension or Code	29. Fax Number *(if applicable)*
(832) 636-1000		(832) 636-5446

30. Primary SIC Code (4 digits)	31. Secondary SIC Code (4 digits)	32. Primary NAICS Code (5 or 6 digits)	33. Secondary NAICS Code (5 or 6 digits)
1311		211111	

34. What is the Primary Business of this entity? *(Please do not repeat the SIC or NAICS description.)*

Oil and Gas Production Facility

Questions 34 – 37 address geographic location. Please refer to the instructions for applicability.

35. Description to Physical Location:	From the intersection of Hwy 302 and Loving County Road 300 in Mentone, Texas, travel north 14 miles on Co Rd 300. Turn left (west) on lease road and travel approx. 1 mile. Arrive at facility.

36. Nearest City	County	State	Nearest ZIP Code
Mentone	Loving	TX	79754

37. Latitude (N) In Decimal:	31.9		38. Longitude (W) In Decimal:	103.7	
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
31	54	13	103	42	46

39. TCEQ Programs and ID Numbers Check all Programs and write in the permits/registration numbers that will be affected by the updates submitted on this form or the updates may not be made. If your Program is not listed, check other and write it in. See the Core Data Form instructions for additional guidance.

☐ Dam Safety	☐ Districts	☐ Edwards Aquifer	☐ Industrial Hazardous Waste	☐ Municipal Solid Waste
☒ New Source Review – Air	☐ OSSF	☐ Petroleum Storage Tank	☐ PWS	☐ Sludge
☐ Stormwater	☒ Title V – Air	☐ Tires	☐ Used Oil	☐ Utilities
☐ Voluntary Cleanup	☐ Waste Water	☐ Wastewater Agriculture	☐ Water Rights	☐ Other:

SECTION IV: Preparer Information

40. Name:	Melissa Dakas	**41. Title:**	Managing Consultant

42. Telephone Number	43. Ext./Code	44. Fax Number	45. E-Mail Address
(512) 349-5800		(512) 233-0803	mdakas@trinityconsultants.com

SECTION V: Authorized Signature

46. By my signature below, I certify, to the best of my knowledge, that the information provided in this form is true and complete, and that I have signature authority to submit this form on behalf of the entity specified in Section II, Field 9 and/or as required for the updates to the ID numbers identified in field 39.

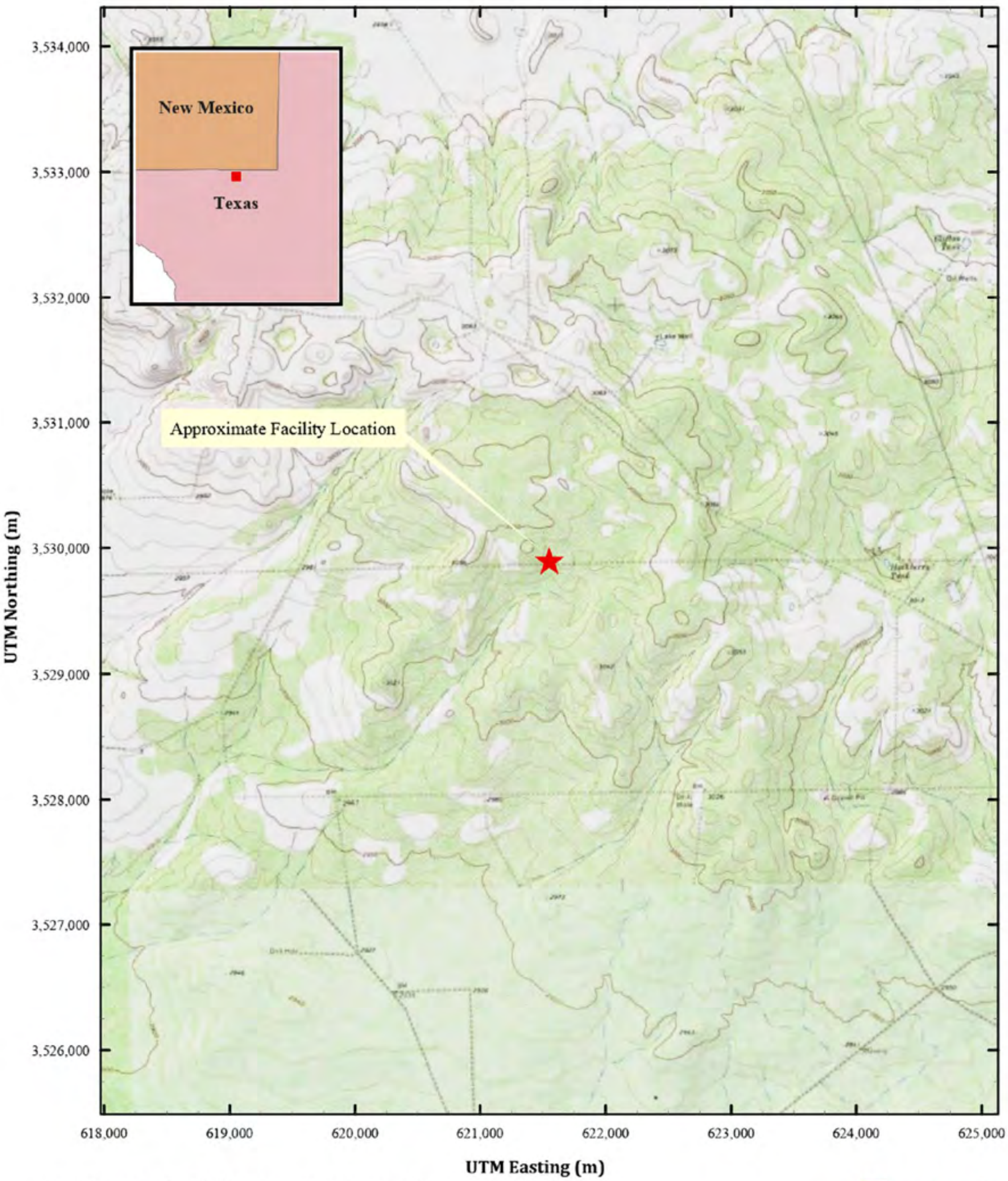
(See the Core Data Form instructions for more information on who should sign this form.)

Company:	Delaware Basin JV Gatherin LLC	**Job Title:**	Operations Manager
Name *(In Print)*:	Charles Griffie	**Phone:**	(832) 636-1000
Signature:	Charles Griff	**Date:**	12/10/2012

4. AREA MAP

The proposed Avalon Mega CGF will be located in Loving County, TX. An area map is included in this section to graphically depict the location of the facility with respect to the surrounding topography. Figure 4-1 is an area map centered on the site and extends out at least 3,000 feet from the property line in all directions. The map depicts the fence line/property line with respect to predominant geographic features (such as highways, roads, streams, and railroads). There are no schools within 3,000 feet of the facility boundary.

Figure 4-1. Area Map
Anadarko Mega CGF
Loving County, Texas

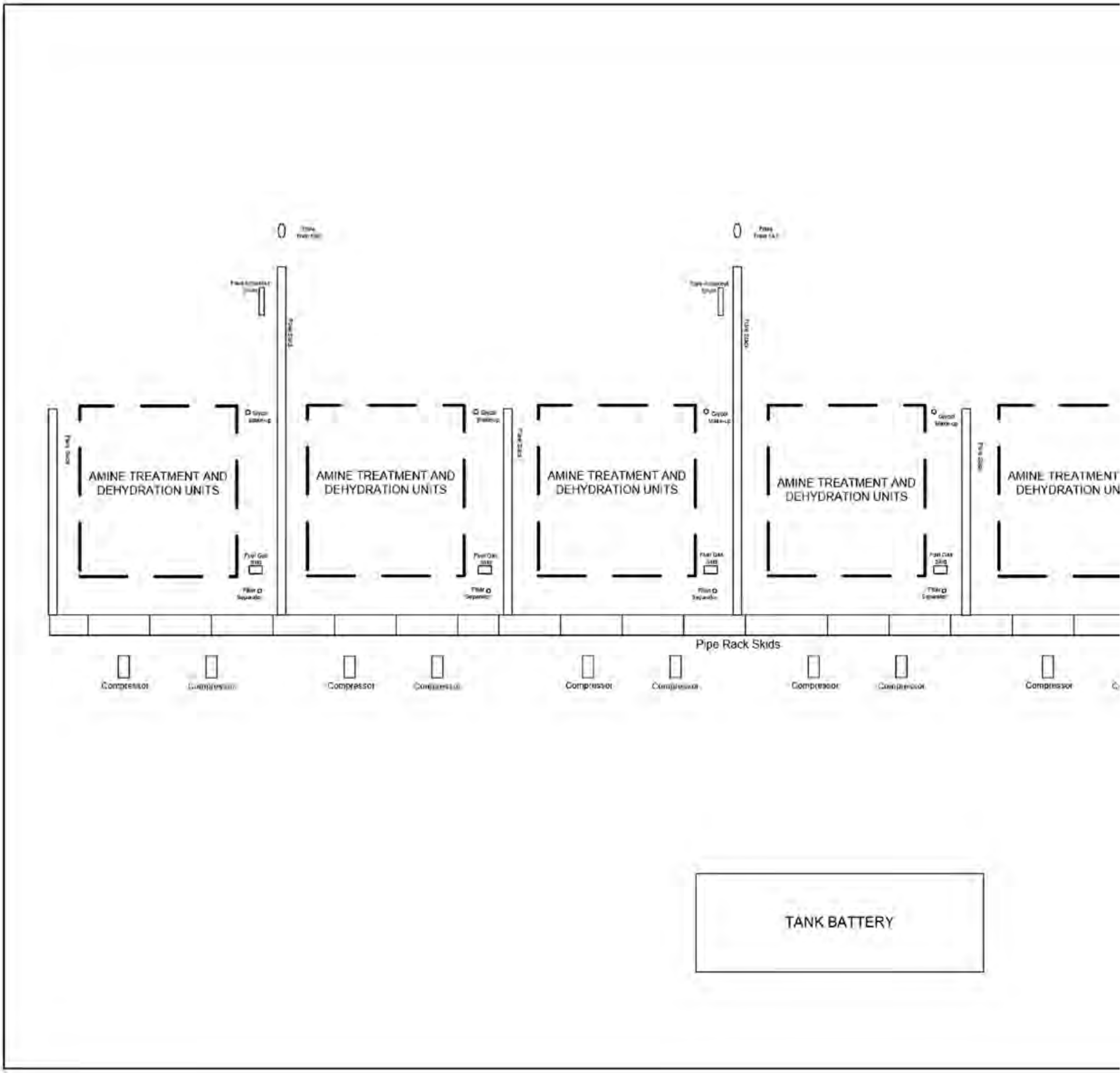


Coordinates reflect UTM projection Zone 13, NAD83.

Trinity Consultants

5. PLOT PLAN

The following figure depicts the site plan for the proposed Avalon Mega CGF.


AMINE TREATMENT AND DEHYDRATION UNITS
AMINE TREATMENT AND DEHYDRATION UNITS
AMINE TREATMENT AND DEHYDRATION UNITS
AMINE TREATMENT AND DEHYDRATION UNITS
Pipe Rack Skids
Compressor
Compressor
Compressor
Compressor
Compressor
TANK BATTERY

6. PROCESS DESCRIPTION & PROCESS FLOW DIAGRAM

The proposed Avalon Mega CGF will be composed of six identical processing trains with the combined ability to process 200 MMscfd of field gas.

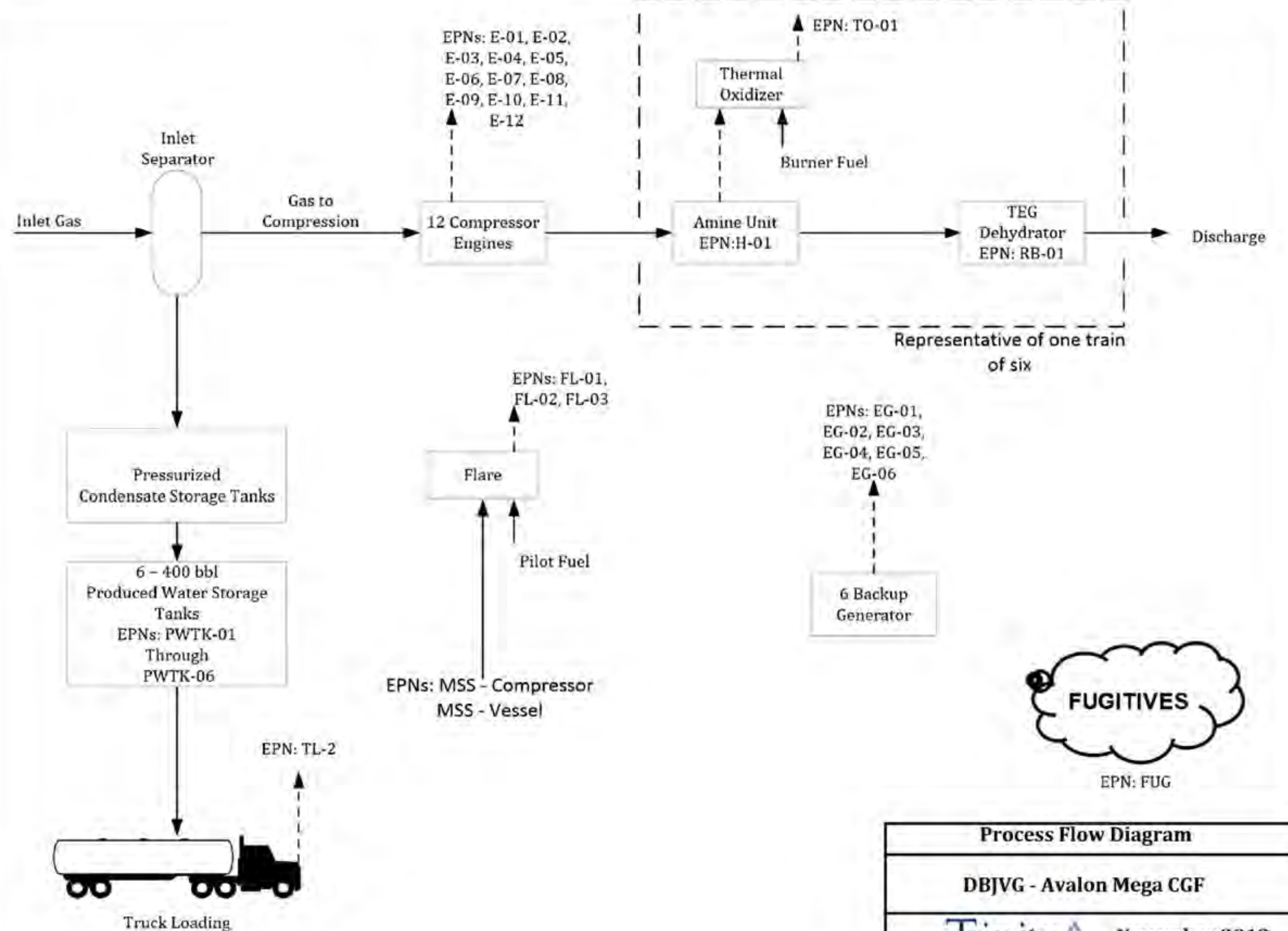
Natural gas entering the Avalon Mega CGF is first sent through a single inlet separator skid to separate liquids from the inlet gas. The resulting liquids are sent to atmospheric produced water tanks (EPNs: PWTK-1, PWTK-2, PWTK-3, PWTK-4, PWTK-5, and PWTK-6) and pressurized condensate storage tanks prior to being loaded to tanker trucks for shipment off-site (EPN: TL-2). The daily maximum liquid production is estimated to be 200 barrels of condensate and 200 barrels of water. The emissions from the produced water storage tanks will be vented to the atmosphere.

The separated gas is compressed by twelve Caterpillar G3612 engines (EPNs: E-01, E-02, E-03, E-04, E-05, E-06, E-07, E-08, E-09, E-10, E-11, and E-12). The compressed inlet gas is then sent to a series of six identical trains for treatment. Each train is equipped with an amine unit for CO_2 removal and a TEG dehydrator for water removal. The amine units (EPNs: H-01, H-02, H-03, H-04, H-05, and H-06) and TEG dehydrators (EPNs: RB-01, RB-02, RB-03, RB-04, RB-05, and RB-06) are equipped with reboilers to promote better separation. The amine still vents are controlled by a thermal oxidizer (EPNs: TO-01, TO-02, TO-03, TO-04, TO-05, and TO-06) and the flash tank emissions are recycled back into the fuel gas system. The TEG dehydrator still vent and flash tank emissions from both units are recycled back into the fuel gas system for the facility.

Additional process emissions at the site result from fugitive emissions (EPN: FUG), and routine maintenance, startup, and shutdown (MSS) emissions from the compressor blowdowns (EPN: MSS-compressors), vessel blowdowns (EPN: MSS-vessel), and pigging operations (EPN: MSS-pigging). The compressor and vessel blowdown emissions are controlled by flares (EPNs: FL-01, FL-02, FL-03), one flare per two trains.

The facility will include six diesel-fired emergency generators (EPNs: EG-01, EG-02, EG-03, EG-04, EG-05, and EG-06). Each engine will be operated less than 100 hours per year for routine testing, maintenance, and inspection purposes only.

Emissions from the proposed equipment are discussed in the following section of this application.



Process Flow Diagram
DBJVG - Avalon Mega CGF
Trinity Consultants — **November 2012** **124401.0095**

This section summarizes the GHG emission calculation methodologies and provides emission calculations for the proposed GHG emission sources:

The following sources of GHG emissions are included in the emission calculations provided in Appendix C:

- Twelve Caterpillar G3612 Engines (EPNs: E-01, E-02, E-03, E-04, E-05, E-06, E-07, E-08, E-09, E-10, E-11, and E-12);
- Six amine reboilers (EPNs: H-01, H-02, H-03, H-04, H-05, and H-06);
- Six amine still vents routed to thermal oxidizers (EPNs: TO-1, TO-2, TO-3, TO-4, TO-5, and TO-6);
- Six TEG dehydrator reboilers (EPNs: RB-01, RB-02, RB-03, RB-04, RB-05, and RB-06);
- Three flares (EPNs: FL-01, FL-02. FL-03);
- Six produced water storage tanks (EPNs: PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, and PWTK-06);
- Six emergency generators (EPNs: EG-01, EG-02, EG-03, EG-04, EG-05, and EG-06);
- Produced water truck loading (EPN: TL-2);
- Site-wide fugitive emissions (EPN: FUG); and
- Site-wide MSS emissions (EPNs: MSS-compressors, MSS-vessel, and MSS-pigging).

The operation of these sources will result in emissions of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).

According to 40 CFR Section (§)52.21(b)(49)(ii), PSD applicability for GHG emissions is determined based on GHG emissions on a carbon dioxide equivalent basis (CO_2e), as calculated by multiplying the mass of each of the six regulated GHGs by the gas' associated Global Warming Potential (GWP).[4] The GWP value for each GHG proposed to be emitted from the project is listed in the following table.

Table 7.1-1. Greenhouse Gas Global Warming Potentials

CO_2	CH_4	N_2O
1	21	310

The following is an example calculation for hourly and annual CO_2e emissions:

$$CO_2e \text{ Hourly Emission Rate } \left(\frac{\text{lb}}{\text{hr}}\right)$$
$$= CO_2 \text{ Hourly Emission Rate } \left(\frac{\text{lb}}{\text{hr}}\right) \times CO_2 \text{ GWP} + CH_4 \text{ Hourly Emission Rate } \left(\frac{\text{lb}}{\text{hr}}\right) \times CH_4 \text{ GWP}$$
$$+ N_2O \text{ Hourly Emission Rate } \left(\frac{\text{lb}}{\text{hr}}\right) \times N_2O \text{ GWP}$$

[4] 40 CFR Part 98, Subpart A, Table A-1.

$$CO_2e \text{ Annual Emission Rate (tpy)} = CO_2 \text{ Annual Emission Rate (tpy)} \times CO_2 \text{ GWP} + CH_4 \text{ Annual Emission Rate (tpy)} \times CH_4 \text{ GWP} + N_2O \text{ Annual Emission Rate (tpy)} \times N_2O \text{ GWP}$$

Emissions of CO_2, CH_4, and N_2O are estimated using the methodologies outlined in EPA's Mandatory Greenhouse Gas Reporting Rule (40 CFR Part 98) or a mass balance approach, as detailed in the remainder of this section.

7.1. COMPRESSOR ENGINES

The project will include twelve natural gas-fired compressor engines (EPNs: E-01, E-02, E-03, E-04, E-05, E-06, E-07, E-08, E-09, E-10, E-11, and E-12). Combustion of natural gas will result in emissions of CO_2, CH_4, and N_2O.

GHG emissions are estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in 40 CFR Part 98 Subpart C for stationary fuel combustion sources and as shown in the following table. [5]

Table 7.1-2. Natural Gas Combustion GHG Emission Factors

Units	CO_2	CH_4	N_2O
kg/MMBtu	53.02	1.0E-03	1.0E-04
lb/MMBtu *	116.89	2.2E-03	2.2E-04

*Emission factors are converted from kilograms to pounds using the conversion factor 2.2046 lb/kg.

Hourly emission rates for CO_2, CH_4, and N_2O are based on the heat input rating (MMBtu/hr) for the engines. Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr. The following equations are used to estimate hourly and annual CO_2, CH_4, and N_2O emission rates from the compressor engines:

$$\text{Hourly Emission Rate } \left(\frac{\text{lb}}{\text{hr}}\right) = \text{Heat Input Rating } \left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \text{ Emission Factor } \left(\frac{\text{lb}}{\text{MMBtu}}\right)$$

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate} \left(\frac{\text{lb}}{\text{hr}}\right) \times \text{ Hours of Operation } \left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000 \text{ lb}}\right)$$

7.2. THERMAL OXIDIZER

The thermal oxidizers (EPNs: TO-01, TO-02, TO-03, TO-04, TO-05, and TO-06) will be used to control emissions from the still vents associated with the amine units. Emissions of CO_2, CH_4, and N_2O from the thermal oxidizers will result from the combustion of pipeline quality natural gas in the pilot and the combustion of waste vent gas from the amine units.

[5] 40 CFR 98 Subpart C, Tables C-1 and C-2.

Emissions from pilot gas combustion are estimated using the methodologies described below, the design pilot gas flow rate, and the natural gas fuel analysis.

GHG emissions from combustion of amine unit waste streams are estimated based on methodologies in 40 CFR Part 98 Subpart W for petroleum and natural gas systems.

Pilot Gas Fuel Emissions

Hourly emission rates for CO_2, CH_4, and N_2O are based on the heat input rating (MMBtu/hr) for the pilot flare. Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr. The following equations are used to estimate hourly and annual emission rates from the pilot flare:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Heat Input Rating}\left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)$$

$$\text{Annual Emission Rate (tpy)} = \text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

Amine Still Vent Emissions

Controlled hourly emission rates for CO_2 and CH_4 from the thermal oxidizer are estimated using the ProMax output for the waste stream resulting from the amine still vent and the guaranteed destruction efficiency. The ProMax simulation output file is provided in Appendix A for reference.

The following equation is used to estimate hourly CO_2 and CH_4 emission rates from the controlled streams:

$$\text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Output}\left(\frac{\text{lb}}{\text{hr}}\right) \times [1 - \text{Destruction Rate Efficiency}(\%)/100]$$

Hourly N_2O emission rates are estimated using Equation W-40 in 40 CFR Part 98 Subpart W for combustion units that combust process vent gas, as shown in the following equation:[6]

$$\begin{aligned}&N_2O\text{ Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right)\\ &\quad = \text{Waste Gas Flowrate}\left(\frac{\text{MMscf}}{\text{day}}\right) \times \frac{1\text{ day}}{24\text{ hr}} \times \frac{10^6\text{ scf}}{1\text{ MMscf}} \times \text{Process Gas HHV}\left(\frac{\text{MMBtu}}{\text{scf}}\right)\\ &\quad \times N_2O\text{ Emission Factor}\left(\frac{\text{kg}}{\text{MMBtu}}\right) \times \frac{2.2046\text{ lb}}{1\text{ kg}}\end{aligned}$$

The process gas HHV is taken from 40 CFR §98.233(z)(2)(vi). The N_2O emission factor is obtained from Table C-2 in 40 CFR Part 98 Subpart C for natural gas.

[6] 40 CFR §98.233(z)(2)(vi).

In addition to emissions from combusted CO_2, CH_4, and N_2O, GHG emissions will result from the conversion of carbon atoms in the waste streams to CO_2. For sources that combust process vent gas, the converted emissions are estimated based on Equations W-39A and W-39B obtained from 40 CFR Part 98 Subpart W.[7] The following equation is used to determine the CO_2 emissions resulting from the oxidation of methane (compounds with one carbon atom), ethane (compounds with two carbon atoms), propane (compounds with three carbon atoms), butanes (compounds with four carbon atoms), and pentanes+ (compounds with five or more carbon atoms):

$$\text{Converted } CO_2 \text{ Hourly Emission Rate} = \text{Output}\left(\frac{\text{lb}}{\text{hr}}\right) \text{ x Carbon Count x Destruction Rate Efficiency } (\%)/100$$

All annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr, using the following equation:

$$\text{Controlled Annual Emission Rate (tpy)} = \text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

7.3. TEG DEHYDRATOR REBOILERS

The TEG dehydrators are equipped with reboilers (EPNs: RB-01, RB-02, RB-03, RB-04, RB-05, and RB-06). Fuel combustion associated with the heating of the reboilers will result in emissions of GHG pollutants. Hourly emission rates for CO_2, CH_4, and N_2O are based on the heat input rating (MMBtu/hr) for the reboiler. Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr. The following equations are used to estimate hourly and annual emission rates from the glycol dehydrator reboilers:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Heat Input Rating}\left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)$$

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

7.4. AMINE UNIT REBOILERS

The amine units are equipped with reboilers (EPNs: H-01, H-02, H-03, H-04, H-05, and H-06). Fuel combustion associated with the heating of the reboilers will result in emissions of GHG pollutants. Hourly emission rates for CO_2, CH_4, and N_2O are based on the heat input rating (MMBtu/hr) for the reboiler. Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr. The following equations are used to estimate hourly and annual emission rates from the amine unit reboilers:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Heat Input Rating}\left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)$$

---

[7] 40 CFR §98.233(z)(2)(iii).

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

7.5. FLARES

The Avalon Mega CGF will include three flares (EPNs: FL-01, FL-02, and FL-03), one flare per two trains, to control MSS emissions and emergency releases. Emissions of CO_2, CH_4, and N_2O from the flares will result from the combustion of pipeline quality natural gas in the pilot and the combustion of gas streams from the compressor and vessel blowdowns during MSS activities.

Emissions from pilot gas combustion are estimated using the methodologies described below, the design pilot gas flow rate, and the natural gas fuel analysis.

Pilot Gas Fuel Emissions

Hourly emission rates for CO_2, CH_4, and N_2O are based on the heat input rating (MMBtu/hr) for the flare pilot. Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr. The following equations are used to estimate hourly and annual emission rates from the pilot flare:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Heat Input Rating}\left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)$$

$$\text{Annual Emission Rate (tpy)} = \text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

MSS Activity Emissions

Emissions from compressor and vessel blowdowns (EPNs: MSS-compressors and MSS-vessel) are estimated by determining the volume of gas per blowdown and the gas speciation. GHG emissions will result from the conversion of carbon atoms in the waste streams to CO_2. For sources that combust process vent gas, the converted emissions are estimated based on Equations W-39A and W-39B obtained from 40 CFR Part 98 Subpart W.[9] The following equation is used to determine the CO_2 emissions resulting from the oxidation of methane (compounds with one carbon atom), ethane (compounds with two carbon atoms), propane (compounds with three carbon atoms), butanes (compounds with four carbon atoms), and pentanes+ (compounds with five or more carbon atoms):

$$\begin{aligned}&CO_2\ \text{Hourly Emission Rate}\\&= \text{Volume (scf)} \times 379.4\left(\frac{\text{lbmol}}{\text{scf}}\right) \times \text{Molecular Weight}\left(\frac{\text{lb}}{\text{lbmol}}\right) \times \%\ CO_2\\&\quad / \text{Hours of Operation (hr)} \times \text{Carbon Count} \times \text{Destruction Rate Efficiency } (\%)/100\end{aligned}$$

All annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr, using the following equation:

---

[9] 40 CFR §98.233(z)(2)(iii).

Controlled Annual Emission Rate (tpy)

$$= \text{Controlled Hourly Emission Rate} \left(\frac{\text{lb}}{\text{hr}}\right) \times \text{ Hours of Operation} \left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

7.6. FUGITIVE COMPONENTS

Process fugitive GHG emissions result from leaking piping components such as valves and flanges (EPN: FUG).

Emissions from fugitive equipment leaks are calculated using fugitive component counts for the proposed equipment, the GHG content of each stream for which component counts are placed in service, and emission factors for each component type taken from the TCEQ Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives.[9] DBJVG has selected to implement the 28 VHP Monitoring Program; therefore, these control efficiencies are applied to the equipment leak fugitive calculations. Additionally, DBJVG will monitor flanges using quarterly organic vapor analyzer (OVA) monitoring at the same leak definition for valves, resulting in the same control efficiency applied to flanges as is applied to valves.

Hourly Emissions

Hourly emissions of GHG from traditional fugitive components (i.e., valves and flanges) are estimated using TCEQ emission factors, component counts, and the GHG content of each stream. The following equation is used to estimate hourly CO_2 and CH_4 emissions:

Hourly Emission Rate (lb/hr)

$$= \text{TCEQ Emission Factor} \left(\frac{\text{lb}}{\text{hr-comp}}\right) \times \text{ Number of Components (\# comp)}$$
$$\times \text{ Compound Content (wt \%)} \times \left(1 - 28 \text{ VHP Control Factor(\%)}\right)$$

Annual Emissions

Annual emissions are estimated based on hourly emissions rates and maximum operation equivalent to 8,760 hrs/yr, as shown in the following equation:

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate} \left(\frac{\text{lb}}{\text{hr}}\right) \times \text{ Hours of Operation} \left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

7.7. FUGITIVE MSS ACTIVITIES

Fugitive CO_2 and CH_4 emissions will occur from maintenance, startup and shutdown activities due to pigging operations (EPN: MSS-pigging) which vent to the atmosphere. Fugitive emissions from the MSS activities are calculated using the following equations:

---

[9] TCEQ, Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Annual Gas Mass}\left(\frac{\text{lb}}{\text{yr}}\right) \times \frac{1}{\text{Annual Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right)} \times \text{Component Mass Percent (\%)}$$

Annual CO_2 and CH_4 emission rates from fugitive MSS activities are estimated based on the annual amount of gas released during pigging operations using the following equation:

$$\text{Annual Emission Rate (tpy)} = \text{Annual Gas Mass}\left(\frac{\text{lb}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

8. EMISSION POINT SUMMARY (TCEQ TABLE 1(A))

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:		Permit No.:	TBD	Regulated Entity No.	TBD
Area Name:	Avalon Mega CGF			Customer Reference No.	CN603815879

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
E-01	E-01	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-02	E-02	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-03	E-03	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-04	E-04	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-05	E-05	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705

Table 1(a) Emission Point Summary

Date:		Permit No.:	TBD	Regulated Entity No.	TBD
Area Name:	Avalon Mega CGF			Customer Reference No.	CN603815879

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
E-06	E-06	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-07	E-07	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-08	E-08	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-09	E-09	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-10	E-10	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705

Table 1(a) Emission Point Summary

Date:		Permit No.:	TBD	Regulated Entity No.	TBD
Area Name:	Avalon Mega CGF			Customer Reference No.	CN603815879

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
E-11	E-11	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-12	E-12	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
EG-01	EG-01	Emergency Generator 1	CO_2	1281	64.07
			CH_4	0.05	<0.01
			N_2O	0.01	<0.01
			CO_2e	1286	64.29
EG-02	EG-02	Emergency Generator 2	CO_2	1281	64.07
			CH_4	0.05	<0.01
			N_2O	0.01	<0.01
			CO_2e	1286	64.29
EG-03	EG-03	Emergency Generator 3	CO_2	1281	64.07
			CH_4	0.05	<0.01
			N_2O	0.01	<0.01
			CO_2e	1286	64.29

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:		Permit No.:	TBD	Regulated Entity No.	TBD
Area Name:	Avalon Mega CGF			Customer Reference No.	CN603815879

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
EG-04	EG-04	Emergency Generator 4	CO_2	1281	64.07
			CH_4	0.05	<0.01
			N_2O	0.01	<0.01
			CO_2e	1286	64.29
EG-05	EG-05	Emergency Generator 5	CO_2	1281	64.07
			CH_4	0.05	<0.01
			N_2O	0.01	<0.01
			CO_2e	1286	64.29
EG-06	EG-06	Emergency Generator 6	CO_2	1281	64.07
			CH_4	0.05	<0.01
			N_2O	0.01	<0.01
			CO_2e	1286	64.29
H-01	H-01	Amine Unit #1 Reboiler	CO_2	4676	20479
			CH_4	0.09	0.39
			N_2O	<0.01	0.04
			CO_2e	4680	20499
H-02	H-02	Amine Unit #2 Reboiler	CO_2	4676	20479
			CH_4	0.09	0.39
			N_2O	<0.01	0.04
			CO_2e	4680	20499

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:		Permit No.:	TBD	Regulated Entity No.	TBD
Area Name:	Avalon Mega CGF			Customer Reference No.	CN603815879

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
H-03	H-03	Amine Unit #3 Reboiler	CO_2	4676	20479
			CH_4	0.09	0.39
			N_2O	<0.01	0.04
			CO_2e	4680	20499
H-04	H-04	Amine Unit #4 Reboiler	CO_2	4676	20479
			CH_4	0.09	0.39
			N_2O	<0.01	0.04
			CO_2e	4680	20499
H-05	H-05	Amine Unit #5 Reboiler	CO_2	4676	20479
			CH_4	0.09	0.39
			N_2O	<0.01	0.04
			CO_2e	4680	20499
H-06	H-06	Amine Unit #6 Reboiler	CO_2	4676	20479
			CH_4	0.09	0.39
			N_2O	<0.01	0.04
			CO_2e	4680	20499
TO-1	TO-1	Thermal Oxidizer 1	CO_2	20058	87853
			CH_4	0.11	0.50
			N_2O	0.05	0.22
			CO_2e	20076	87932

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:		Permit No.:	TBD	Regulated Entity No.	TBD
Area Name:	Avalon Mega CGF			Customer Reference No.	CN603815879

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
TO-2	TO-2	Thermal Oxidizer 2	CO_2	20058	87853
			CH_4	0.11	0.50
			N_2O	0.05	0.22
			CO_2e	20076	87932
TO-3	TO-3	Thermal Oxidizer 3	CO_2	20058	87853
			CH_4	0.11	0.50
			N_2O	0.05	0.22
			CO_2e	20076	87932
TO-4	TO-4	Thermal Oxidizer 4	CO_2	20058	87853
			CH_4	0.11	0.50
			N_2O	0.05	0.22
			CO_2e	20076	87932
TO-5	TO-5	Thermal Oxidizer 5	CO_2	20058	87853
			CH_4	0.11	0.50
			N_2O	0.05	0.22
			CO_2e	20076	87932
TO-6	TO-6	Thermal Oxidizer 6	CO_2	20058	87853
			CH_4	0.11	0.50
			N_2O	0.05	0.22
			CO_2e	20076	87932
RB-01	RB-01	Glycol Dehydrator #1 Reboiler	CO_2	175	768
			CH_4	<0.01	0.01
			N_2O	<0.01	<0.01
			CO_2e	176	769

Table 1(a) Emission Point Summary

Date:		Permit No.:	TBD	Regulated Entity No.	TBD
Area Name:	Avalon Mega CGF			Customer Reference No.	CN603815879

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
RB-02	RB-02	Glycol Dehydrator #2 Reboiler	CO_2	175	768
			CH_4	<0.01	0.01
			N_2O	<0.01	<0.01
			CO_2e	176	769
RB-03	RB-03	Glycol Dehydrator #3 Reboiler	CO_2	175	768
			CH_4	<0.01	0.01
			N_2O	<0.01	<0.01
			CO_2e	176	769
RB-04	RB-04	Glycol Dehydrator #4 Reboiler	CO_2	175	768
			CH_4	<0.01	0.01
			N_2O	<0.01	<0.01
			CO_2e	176	769
RB-05	RB-05	Glycol Dehydrator #5 Reboiler	CO_2	175	768
			CH_4	<0.01	0.01
			N_2O	<0.01	<0.01
			CO_2e	176	769
RB-06	RB-06	Glycol Dehydrator #6 Reboiler	CO_2	175	768
			CH_4	<0.01	0.01
			N_2O	<0.01	<0.01
			CO_2e	176	769

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:		Permit No.:	TBD	Regulated Entity No.	TBD
Area Name:	Avalon Mega CGF			Customer Reference No.	CN603815879

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
FL-01	FL-01	Flare #1	CO_2	35.51	156
			CH_4	<0.01	<0.01
			N_2O	<0.01	<0.01
			CO_2e	35.54	156
FL-02	FL-02	Flare #2	CO_2	35.51	156
			CH_4	<0.01	<0.01
			N_2O	<0.01	<0.01
			CO_2e	35.54	156
FL-03	FL-03	Flare #3	CO_2	35.51	156
			CH_4	<0.01	<0.01
			N_2O	<0.01	<0.01
			CO_2e	35.54	156

TCEQ

Table 1(a) Emission Point Summary

Date:		Permit No.:	TBD	Regulated Entity No.	TBD
Area Name:	Avalon Mega CGF			Customer Reference No.	CN603815879

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
FUG	FUG	Fugitive Emissions	CO_2	<0.01	<0.01
			CH_4	<0.01	<0.01
			CO_2e	<0.01	<0.01
PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, PWTK-06	PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, PWTK-06	Produced Water Tanks	CO_2	<0.01	<0.01
			CH_4	<0.01	0.01
			CO_2e	0.06	0.30
TL-2	TL-2	Produced Water Truck Loading	CH_4	<0.01	<0.01
			CO_2e	<0.01	<0.01
MSS-compressors	FL-01, FL-02, FL-03	MSS - Compressor Blowdowns	CO_2	10.63	9.95
			CH_4	0.18	0.17
			CO_2e	14.39	13.47
MSS-vessel	FL-01, FL-02, FL-03	MSS - Vessel Blowdown	CO_2	48.22	0.40
			CH_4	0.81	<0.01
			CO_2e	65.27	0.54
MSS-pigging	MSS-pigging	MSS- Pigging Operations	CO_2	0.43	<0.01
			CH_4	0.01	<0.01
			CO_2e	0.68	<0.01

9. FEDERAL NEW SOURCE REVIEW REQUIREMENTS

This section addresses the applicability of the following parts of 40 CFR for the equipment at the proposed Avalon Mega CGF Gas Plant:

- Nonattainment New Source Review (NNSR)
- Prevention of Significant Deterioration (PSD)

All applicable state and federal requirements (e.g., New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants), with the exception to those pertaining to GHG emissions, are addressed in the TCEQ NSR permit application.

9.1. NNSR APPLICABILITY REVIEW

The Avalon Mega CGF facility will be located in Loving County, Texas, which has been designated as attainment area for all criteria pollutants. Under EPA and TCEQ rules, sites located in areas that are designated in attainment of the National Ambient Air Quality Standards (NAAQS) for a criteria pollutant are potentially regulated under the PSD program if they are considered major sources. Major source thresholds are defined in 40 CFR §52.21 (b)(1)(i). The Avalon Mega CGF will be considered a major source under PSD and therefore, not subject to NNSR permitting requirements.

9.2. PSD APPLICABILITY REVIEW

The proposed Avalon Mega CGF will be a new major source with respect to GHG emissions and subject to PSD permitting requirements under the GHG Tailoring Rule[10]. In the Tailoring Rule, EPA established a major source threshold of 100,000 tpy CO_2e for new GHG sources and a major modification threshold of 75,000 tpy CO_2e for existing major sources. DBJVG has determined that the GHG emissions from the proposed project will exceed 100,000 tpy. With a final action published in May 2011, EPA promulgated a FIP to implement the permitting requirements for GHGs in Texas, and EPA assumed the role of permitting authority for Texas GHG permit applications.[11] Therefore, GHG emissions from the proposed project are subject to the jurisdiction of the EPA under authority asserted in Texas through the aforementioned FIP.

As shown in the TCEQ application, the facility's emissions of non-GHG criteria pollutants will also exceed the PSD major source thresholds (i.e. > 250 tpy of NO_x and CO). Therefore, the proposed project will be subject to PSD permitting requirements for non-GHG criteria emissions and the project is subject to the jurisdiction of the TCEQ for major source NSR permitting of such emissions. Accordingly, DBJVG is submitting applications to both EPA and TCEQ to obtain the requisite authorizations to construct.

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[10] Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514 (June 3, 2010).

[11] Determinations Concerning Need for Error Correction, Partial Approval and Partial Disapproval, and Federal Implementation Plan Regarding Texas's Prevention of Significant Deterioration Program, 76 Fed. Reg. 25,178 (May 3, 2011).

This section discusses the approach used in completing the GHG BACT analysis, as well as documenting the emission units for which the GHG BACT analyses were performed.

10.1. BACT DEFINITION

The requirement to conduct a BACT analysis is set forth in the PSD regulations in 40 CFR §52.21(j)(2):

(j) Control Technology Review.

(2) A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.

BACT is defined in the PSD regulations 40 CFR §52.21(b)(12)(emphasis added) in relevant part as:

...an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such a source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61.

Although this definition was not changed by the Tailoring Rule, differences in the characteristics of criteria pollutant and GHG emissions from large industrial sources present several GHG-specific considerations under the BACT definition which warrant further discussion. Those underlined terms in the BACT definition are addressed further below.

10.1.1. Emission Limitation

BACT is "an emission limitation," not an emission reduction rate or a specific technology. While BACT is prefaced upon the application of technologies reflecting the maximum reduction rate achievable, the final result of BACT is an emission limit. Typically when quantifiable and measurable[12], this limit would be expressed as an emission rate limit of a pollutant (e.g., lb/MMBtu, ppm, or lb/hr).[13] Furthermore, EPA's guidance on GHG BACT has indicated that GHG BACT limitations should be averaged over long-term timeframes such as 30- or 365-day rolling average.[14]

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[12] The definition of BACT allows use of a work practice where emissions are not easily measured or enforceable. 40 CFR §52.21(b)(12).

[13] Emission limits can be broadly differentiated as "rate-based" or "mass-based." For a turbine, a rate-based limit would typically be in units of lb/MMBtu (mass emissions per heat input). In contrast, a typical mass-based limit would be in units of lb/hr (mass emissions per time).

[14] *PSD and Title V Permitting Guidance for Greenhouse Gases*. March 2011, page 46.

10.1.2. Each Pollutant

Since BACT applies to "each pollutant subject to regulation under the Act," the BACT evaluation process is typically conducted for each regulated NSR pollutant individually and not for a combination of pollutants.[15] For PSD applicability assessments involving GHGs, the regulated NSR pollutant subject to regulation under the Clean Air Act (CAA) is the sum of six greenhouse gases and not a single pollutant.[16] In the final Tailoring Rule preamble, EPA went beyond applying this combined pollutant approach for GHGs to PSD applicability and made the following recommendations that suggest applicants should conduct a single GHG BACT evaluation on a CO_2e basis for emission sources that emit more than one GHG:

> *However, we disagree with the commenter's ultimate conclusion that BACT will be required for each constituent gas rather than for the regulated pollutant, which is defined as the combination of the six well-mixed GHGs. To the contrary, we believe that, in combination with the sum-of-six gases approach described above, the use of the CO_2e metric will enable the implementation of flexible approaches to design and implement mitigation and control strategies that look across all six of the constituent gases comprising the air pollutant (e.g., flexibility to account for the benefits of certain CH_4 control options, even though those options may increase CO_2). Moreover, we believe that the CO_2e metric is the best way to achieve this goal because it allows for tradeoffs among the constituent gases to be evaluated using a common currency.*[17]

DBJVG acknowledges the potential benefits of conducting a single GHG BACT evaluation on a CO_2e basis for the purposes of addressing potential tradeoffs among constituent gases for certain types of emission units. However, for the proposed Avalon Mega CGF, the GHG emissions are driven primarily by CO_2. CO_2 emissions represent more than 99% of the total CO_2e for the project as a whole. As such, the following top-down GHG BACT analysis should and will focus on CO_2.

10.1.3. BACT Applies to the Proposed Source

BACT applies to the type of source proposed by the applicant. BACT does not redefine the source. The applicant defines the source (i.e., its goals, aims and objectives). Although BACT is based on the type of source as proposed by the applicant, the scope of the applicant's ability to define the source is not absolute. A key task for the reviewing agency is to determine which parts of the proposed process are inherent to the applicant's purpose and which parts may be changed without changing that purpose. DBJVG has provided project discussion in Section 6 of this report to aid the technical reviewers in need and scope of this project and how GHG BACT should be reviewed in light of this detailed information.

10.1.4. Case-By-Case Basis

Unlike many of the CAA programs, the PSD program's BACT evaluation is case-by-case. BACT permit limits are not simply the requirement for a control technology because of its application elsewhere or the direct transference of the lowest emission rate found in other permits for similar sources, applied to the proposed source. EPA has explained how the top-down BACT analysis process works on a case-by-case basis. To assist applicants and regulators with the

[15] 40 CFR §52.21(b)(12)

[16] 40 CFR § 52.21(b)(49)(i)

[17] 75 FR 31,531, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule, June 3, 2010.*

case-by-case process, in 1990 EPA issued a Draft Manual on New Source Review permitting which included a "top-down" BACT analysis.

> *In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent--or "top"--alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.*[18]

The five steps in a top-down BACT evaluation can be summarized as follows:

- Step 1. Identify all available control technologies;
- Step 2. Eliminate technically infeasible options;
- Step 3. Rank the technically feasible control technologies by control effectiveness;
- Step 4. Evaluate most effective controls; and
- Step 5. Select BACT.

While this EPA-recommended five-step process can be directly applied to GHGs without any significant modifications, it is important to note that the top-down process is conducted on a unit-by-unit, pollutant-by-pollutant basis and only considers the portions of the facility that are considered "emission units" as defined under the PSD regulations.[19]

10.1.5. Achievable

BACT is to be set at the lowest value that is "achievable." However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life. As discussed by the DC Circuit Court of Appeals:

> *In National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980), we said that where a statute requires that a standard be "achievable," it must be achievable" under most adverse circumstances which can reasonably be expected to recur."*[20]

EPA has reached similar conclusions in prior determinations for PSD permits.

> *Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability*

[18] Draft NSR Manual at B-2. "The NSR Manual has been used an a guidance document in conjunction with new source review workshops and training, and as a simple guide for state and federal permitting officials with respect to PSD requirements and policy. Although it is not binding Agency regulation, the NSR Manual has been looked to be this Board as a statement of the Agency's thinking on certain PSD issues. E.g., *In re RockGen Energy Ctr.*, 8 E.A.D. 536, 542 n. 10 (EAB 1999), *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 129 n. 13 (EAB 1999)." *In re Prairie State Generating Company* 13 E.A.D. 1, 13 n 2 (2006)

[19] Pursuant to 40 CFR §52.21(a)(7), emission unit means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant.

[20] As quoted in Sierra Club v. U.S. EPA (97-1686).

in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility. Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.[21]

Thus, BACT must be set at the lowest feasible emission rate recognizing that the facility must be in compliance with that limit for the lifetime of the facility on a continuous basis. While viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life.

To assist in meeting the BACT limit, the source must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source.

10.1.6. Production Process

The definition of BACT lists both production processes and control technologies as possible means for reducing emissions.

10.1.7. Available

The term "available" in the definition of BACT is implemented through a feasibility analysis – a determination that the technology being evaluated is demonstrated or available and applicable.

10.1.8. Floor

For criteria pollutants, the least stringent emission rate allowable for BACT is any applicable limit under either New Source Performance Standards (NSPS – Part 60) or National Emission Standards for Hazardous Air Pollutants (NESHAP – Parts 61). Since no GHG limits have been incorporated into any existing NSPS or Part 61 NESHAPs, no floor for a GHG BACT analysis is available for consideration.

On March 27, 2012, the EPA Administrator signed proposed Standards of Performance for GHG Emissions for Electric Utility Generating Units by adding Subpart TTTT to 40 CFR Part 60 (NSPS Subpart TTTT). This proposed NSPS is not applicable to the emission sources included in this application.

10.2. GHG BACT ASSESSMENT METHODOLOGY

GHG BACT for the proposed project has been evaluated via a "top-down" approach which includes the steps outlined in the following subsections.

[21] U.S. EPA Environmental Appeals Board decision, *In re: Newmont Nevada Energy Investment L.L.C.* PSD Appeal No. 05-04, decided December 21, 2005. Environmental Administrative Decisions, Volume 12, Page 442.

EPA's March 2011 GHG Permitting Guidance generally directed that a BACT review for GHGs should be done in the same manner as it is done for any other regulated pollutant.[22] It should be noted that the scope of a BACT review was clarified in two ways with respect to GHGs:

- EPA stressed that applicants should clearly define the scope of the project being reviewed.[23] DBJVG has provided this information in Section 6 of this application.
- EPA clarified that the scope of the BACT should focus on the project's largest contributors to CO_2e and may subject less significant contributors for CO_2e to less stringent BACT review.[24] Because the project's GHG emissions are dominated by the compressor engines, amine reboilers, and the amine units via the thermal oxidizers, this BACT analysis focuses mainly on these predominant sources of CO_2e from the project.

10.2.1. Step 1 - Identify All Available Control Technologies

Available control technologies for CO_2e with the practical potential for application to the emission unit are identified. The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts, control technologies with potential application to the emission unit under review are identified in this step.

Under Step 1 of a criteria pollutant BACT analysis, the following resources are typically consulted when identifying potential technologies:

1. EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;
2. Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies;
3. Engineering experience with similar control applications;
4. Information provided by air pollution control equipment vendors with significant market share in the industry; and/or
5. Review of literature from industrial technical or trade organizations.

EPA's "top-down" BACT analysis procedure also recommends the consideration of inherently lower emitting processes as available control options under Step 1.[25] For GHG BACT analyses, low-carbon intensity fuel selection is the primary control option that can be considered a lower emitting process. DBJVG proposes the use of pipeline quality natural gas only for all combustion equipment associated with the proposed project. Table C-1 of 40 CFR Part 98 shows CO_2 emissions per unit heat input (MMBtu) for a wide variety of industrial fuel types. Only biogas (captured methane) and coke oven gas result in lower CO_2 emissions per unit heat input than natural gas.

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[22] *PSD and Title V Permitting Guidance for Greenhouse Gases*. March 2011, page 17.

[23] *PSD and Title V Permitting Guidance for Greenhouse Gases*. March 2011, pages 22-23.

[24] *PSD and Title V Permitting Guidance for Greenhouse Gases*. March 2011, page 31.

[25] *PSD and Title V Permitting Guidance for Greenhouse Gases*. March 2011, page 24.

10.2.2. Step 2 - Eliminate Technically Infeasible Options

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling GHG emissions from the source in question. The first question in determining whether or not a technology is feasible is whether or not it is demonstrated. If so, it is feasible. Whether or not a control technology is demonstrated is considered to be a relatively straightforward determination.

> Demonstrated "means that it has been installed and operated successfully elsewhere on a similar facility." *Prairie State*, slip op. at 45. "This step should be straightforward for control technologies that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible."[26]

An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available".[27] Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative. The NSR Manual explains the concept of applicability as follows: "An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration."[28] Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual.

10.2.3. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

All remaining technically feasible control options are ranked based on their overall control effectiveness for GHG. For GHGs, this ranking may be based on energy efficiency and/or emission rate.

10.2.4. Step 4 - Evaluate Most Effective Controls and Document Results

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration it is selected as the basis for the BACT limit. Alternatively, in the judgment of the permitting agency, if unreasonable adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified. EPA recognized in its BACT guidance for GHGs that "[e]ven if not eliminated at Step 2 of the BACT analysis,

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[26] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.17.

[27] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

[28] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible."[29]

The energy, environment, and economic impacts analysis under Step 4 of a GHG BACT assessment presents a unique challenge with respect to the evaluation of CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a proportional increase in emissions of another GHG (i.e., CO_2). However, since the GWP of CH_4 is 21 times higher than CO_2, conversion of CH_4 emissions to CO_2 results in a net reduction of CO_2e emissions.

Permitting authorities have historically considered the effects of multiple pollutants in the application of BACT as part of the PSD review process, including the environmental impacts of collateral emissions resulting from the implementation of emission control technologies. To clarify the permitting agency's expectations with respect to the BACT evaluation process, states have sometimes prioritized the reduction of one pollutant above another. For example, technologies historically used to control NO_x emissions frequently caused increases in CO emissions. Accordingly, several states prioritized the reduction of NO_x emissions above the reduction of CO emissions, approving low NO_x control strategies as BACT that result in higher CO emissions relative to the uncontrolled emissions scenario.

10.2.5. Step 5 - Select BACT

In the final step, the BACT emission limit is determined for each emission unit under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology. BACT is an emission limit unless technological or economic limitations of the measurement methodology would make the imposition of an emissions standard infeasible, in which case a work practice or operating standard can be imposed.

Establishing an appropriate averaging period for the BACT limit is a key consideration under Step 5 of the BACT process. Localized GHG emissions are not known to cause adverse public health or environmental impacts. Rather, EPA has determined that GHG emissions are anticipated to contribute to long-term environmental consequences on a global scale. Accordingly, EPA's Climate Change Workgroup has characterized the category of regulated GHGs as a "global pollutant." Given the global nature of impacts from GHG emissions, NAAQS are not established for GHGs in the Tailoring Rule and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs. Since localized short-term health and environmental effects from GHG emissions are not recognized, DBJVG proposes only long-term averaging periods (i.e. 365 day rolling average) for each GHG BACT limit.

10.3. GHG BACT REQUIREMENT

The GHG BACT requirement applies to each new emission unit from which there are emissions increases of GHG pollutants subject to PSD review. The estimated emissions increase of GHGs from the proposed project will be greater

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[29] *PSD and Title V Permitting Guidance for Greenhouse Gases.* March 2011, pages 42-43.

than 100,000 tpy on a CO_2e basis primarily due to the removal of CO_2 from the field gas in the amine units and the combustion of natural gas in the compressor engines and amine reboilers.

Potential emissions of GHGs from the proposed project will result from the following emission units:

- Twelve Caterpillar G3612 Engines (EPNs: E-01, E-02, E-03, E-04, E-05, E-06, E-07, E-08, E-09, E-10, E-11, and E-12);
- Six amine reboilers (EPNs: H-01, H-02, H-03, H-04, H-05, and H-06);
- Six amine still vents routed to thermal oxidizers (EPNs: TO-1, TO-2, TO-3, TO-4, TO-5, and TO-6);
- Six TEG dehydrator reboilers (EPNs: RB-01, RB-02, RB-03, RB-04, RB-05, and RB-06);
- Three flares (EPNs: FL-01, FL-02, FL-03);
- Six emergency generators (EPNs: EG-01, EG-02, EG-03, EG-04, EG-05, and EG-06); and
- Site-wide fugitive emissions (EPN: FUG).

DBJVG is also proposing to construct six produced water storage tanks (EPNs: PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, and PWTK-06), and to conduct produced water truck loading operations (EPN: TL-2). However, based on the characteristics of the produced water tank contents; the GHG emissions from these sources have been determined to be negligible and emission for these operations are not included in this GHG PSD BACT analysis. In addition, GHG emissions from small emission sources such as MSS activities are not included in the BACT analysis. GHG emissions from these negligible sources will be minimized through the employment of work practices.

The emission calculations provided in Section 7 and Appendix C include a summary of the estimated maximum annual potential to emit GHG emission rates for the proposed Avalon Mega CGF. GHG emissions for each emission unit were estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Gas Reporting Rule (40 CFR 98, Subpart C and Subpart W).

The following guidance documents were utilized as resources in completing the GHG BACT evaluation for the proposed project:

- *PSD and Title V Permitting Guidance for Greenhouse Gases* (hereafter referred to as General GHG Permitting Guidance)[30]
- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Industrial Boilers* (hereafter referred to as GHG BACT Guidance for Boilers)[31]
- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry* (hereafter referred to as GHG BACT Guidance for Refineries)[32]

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[30] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: March 2011). http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

[31] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf

[32] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/refineries.pdf

10.4. GHG BACT EVALUATION FOR PROPOSED EMISSION SOURCES

The following is a summary of BACT for the control of GHG emissions from the proposed Avalon Mega CGF following the EPA's five-step "top-down" BACT process. The table at the end of this section summarizes each step of the BACT analysis for the emission units included in this review. DBJVG is proposing the use of good combustion practices for all combustion sources at the proposed facility. A table detailing good combustion practices is included at the end of this section.

Table 10.4-1 provides a summary of the proposed BACT limits discussed in the following sections.

Table 10.4-1. Proposed GHG BACT Limits for Avalon Mega CGF

EPN	Description	Proposed BACT Limit
E-1 through E-12	Caterpillar G3612 Compressor Engines	13,705 tpy CO_2e per engine
H-01 through H-06 and RB-1 through RB-6	Amine Reboilers and TEG Dehydrator Reboilers	3,822 lb CO_2/MMscf (per train)
TO-1 through TO-6	Amine Still Vent Routed to a Thermal Oxidizer	Work Practices
FL-1, FL-2, and FL-3	Flares	Work Practices
EG-01, EG-02, EG-03, EG-04, EG-05, and EG-06	Emergency Generators	Work Practices
FUG	Fugitive Emissions	Work Practices

10.5. OVERALL PROJECT ENERGY EFFICIENCY CONSIDERATIONS

While the five-step BACT analysis is the EPA's preferred methodology with respect to selection of control technologies for pollutants, EPA has also indicated that an overarching evaluation of energy efficiency should take place as increases in energy efficiency will inherently reduce the total amount of GHG emissions produced by the source. As such, overall energy efficiency was a basic design criterion in the selection of technologies and processing alternatives to be installed at the proposed Avalon Mega CGF.

The new 200 MMscfd Avalon Mega CGF will be designed and constructed using new or updated energy efficient equipment. The plant was designed with heat and process integration in mind for increased energy efficiency. Where feasible, the facility utilizes available process streams to transfer heat which reduces combustion heating requirements in the process. Equipment (vessels), piping, and components in hot service to will be designed to prevent heat lose to the atmosphere from equipment containing hot streams.

The facility will recycle the flash gas from the amine units and flash gas and still vent from the TEG reboiler back to the fuel gas system instead of sending these vents to a control device. The recycling of this material will reduce the amount of natural gas required to fuel the facility's combustion sources and will avoid the formation of additional GHG from combusting this material in a control device.

Process control instrumentation and pneumatic components will be operated using compressed air rather than fuel gas or off-gas; therefore, no GHG emissions will be emitted to the atmosphere from these components. The plant will be built using new, state-of-the-art equipment and process instrumentation and controls. DBJVG operating and maintenance policies will maintain all equipment according to manufacturer specifications in order to keep all equipment operating efficiently.

Table 10.4-2. Summary of Proposed Good Combustion Practices[1]

Good Combustion Technique	Practice	Applicable Units	Standard
Operator practices	• Official documented operating procedures, updated as required for equipment or practice change • Procedures include startup, shutdown, malfunction • Operating logs/record keeping.	All combustion units	• Maintain written site specific operating procedures in accordance with GCPs, including startup, shutdown, and malfunction.
Maintenance knowledge	• Training on applicable equipment & procedures.	All combustion units	• Equipment maintained by personnel with training specific to equipment.
Maintenance practices	• Official documented maintenance procedures, updated as required for equipment or practice change • Routinely scheduled evaluation, inspection, overhaul as appropriate for equipment involved • Maintenance logs/record keeping.	All combustion units	• Maintain site specific procedures for best/optimum maintenance practices • Scheduled periodic evaluation, inspection, and overhaul as appropriate.
Firebox (furnace) residence time, temperature, turbulence	• Supplemental stream injection into active flame zone • Residence time by design (incinerators) • Minimum combustion chamber temperature (incinerators).	Thermal Oxidizers and Flares	
Fuel quality analysis and fuel handling	• Monitor fuel quality • Periodic fuel sampling and analysis • Fuel handling practices • DBJVG will use clean and treated field gas as fuel	All combustion units	• Fuel analysis where composition could vary • Fuel handling procedures applicable to the fuel.
Combustion air distribution	• Adjustment of air distribution system based on visual observations • Adjustment of air distribution based on continuous or periodic monitoring.	All combustion units	• Routine & periodic adjustments & checks.

[1] EPA Guidance document "Good Combustion Practices" available at: http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf.

11. GHG BACT EVALUATION FOR PROPOSED EMISSION SOURCES

The following is an analysis of BACT for the control of GHG emissions from the proposed project following the EPA's five-step "top-down" BACT process. DBJVG is proposing the use of good combustion practices for all combustion sources at the proposed facility.

11.1. AMINE UNIT STILL VENT

The amine units at the Avalon Mega CGF will be used to remove CO_2 in order to meet pipeline specifications for transportation of the natural gas. Because the amine unit is designed to remove CO_2 from the inlet gas stream, the generation of CO_2 is inherent to the process, and any reduction of the CO_2 emissions by process changes would reduce the process efficiency. This would result in a greater CO_2 content in the natural gas that would eventually be emitted. The process-based CO_2 emissions emitted from the amine still vents are calculated based on the estimated flow rate and gas composition of the waste gas.

11.1.1. Step 1 – Identify All Available Control Technologies

The available GHG emission control options for the process emissions include:

- Carbon Capture and Sequestration (CCS);
- Flare;
- Thermal Oxidizer;
- Condenser;
- Proper Design and Operation; and
- Use of Tank Flash Gas Recovery Systems.

11.1.1.1. Carbon Capture and Sequestration

DBJVG engaged the Wood Group Mustang (WGM) to conduct research and analysis to determine the technical feasibility of CO_2 capture and transfer from the Avalon Mega CGF Facility. Since most of the CO_2 emissions from the proposed project are generated from the amine units, the study was designed to evaluate potential options to capture and transfer to an existing pipeline.

Based on the results of these studies, capture and transfer of CO_2 from the amine units is technically feasible. The study evaluated the potential options for capture and transfer of CO_2 from the Avalon Mega CGF (located near Mentone in Loving County, TX) to nearby CO_2 pipelines. The transfer of the CO_2 stream will require further treatment to remove contaminants and compression for transfer.

Since capture and transfer of CO_2 off-site is technically feasible for the proposed project, this option is further evaluated for energy, environmental, and economic impacts.

11.1.1.2. Flare

The use of a flare can only reduce the CH_4 emissions contained in the Avalon Mega CGF stripped amine acid gases. The flare is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Controlling the amine still vent streams with a flare would also require significant supplemental fuel to increase the heating value of the waste gases to the point that it can be effectively combusted in a flare at 300 Btu/ft^3. This will create collateral CO_2 and CH_4 emissions from the additional combustion of the fuel gas and increase the overall CO_2e emissions from this control device. Flares have a destruction efficiency rate (DRE) of 98% for VOCs and 99% for compounds containing no more than 3 carbons and that contain no elements other than carbon and hydrogen, including CH_4. Additionally, the flare requires the use of a continuous pilot ignition system or equivalent that results in additional GHG emissions from natural gas combustion in the pilot. The combustion of the supplemental fuel and pilot fuel result in an overall increase in the net CO_2e emissions from this source.

11.1.1.3. Thermal Oxidizer

Another option to reduce the CH_4 emitted from the Avalon Mega CGF facility is to send stripped amine acid gases to a thermal oxidizer (TO). The TO is also an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions, the control of CH_4 in the process gas at the TO results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions. A regenerative thermal oxidizer (RTO) has a high efficiency heat recovery. This allows the facility to recover heat from the exhaust stream, reducing the overall heat input of the plant. In general, TOs have destruction and removal efficiency (DRE) greater than of 99% for all VOC and HAP compounds, which is more efficient than a typical flare. In contrast with a flare, which requires the use of supplemental fuel to increase the waste gas heating value as well as a constant pilot, a RTO only uses a minimal amount of natural gas to get up to the optimum temperature for combustion resulting in lower use of supplemental fuel and lower GHG emissions.

11.1.1.4. Condenser

Condensers are supplemental emissions control that reduces the temperature of the still column vent vapors on amine units to condense water and VOCs, including CH_4. The condensed liquids are then collected for further treatment or disposal. The reduction efficiency of the condensers is variable and depends on the type of condenser and the composition of the waste gas, ranging from 50-98% of CH_4 emissions.

11.1.1.5. Proper Design and Operations

The amine unit will be new or updated equipment installed on site. New or updated equipment has better energy efficiency, hence reducing the GHGs emitted during combustion. The amine unit will operate at a minimum circulation rate with consistent amine concentrations. By minimizing the circulation rate, the equipment avoids pulling out additional VOCs and GHGs in the amine streams, which would increase VOC and GHG emissions into the atmosphere.

11.1.1.6. Use of Tank Flash Gas Recovery Systems

The amine units will be equipped with flash tanks. The flash tanks will be used to recycle off-gases formed as the pressure of the rich glycol/rich amine streams drops to remove lighter compounds in the stream prior to entering the reboiler. These off-gases are recycled back into the plant for reprocessing, instead of venting to the atmosphere or combustion device. The use of flash tanks increases the effectiveness of other downstream control devices.

11.1.2. Step 2 – Eliminate Technically Infeasible Options

All control options identified in Step 1 are technically feasible.

11.1.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The control options for minimizing GHG emissions from the amine still vent are ranked below:

Rank	Control Technology	Estimated CO_2e Reduction	Reduction Details	Reference
1	Carbon Capture and Sequestration	80%	Reduction of all GHGs.	Report of the Interagency Task Force on Carbon Capture and Storage issued by EPA August 2010 Section III.A.2 Status of Capture Technology
2	Proper Design and Operation	1% - 10%	Reduction of all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 5.1.1.5 Improved Maintenance
3	Condenser	< 0.25%	Reduction of CH_4 in acid gas and dehydrate waste gas.	Vendor Data
4	Use of Tank Flash Gas Recovery Systems	< 0.25%	Reduction of CH_4 in flash gas only.	Hard piped back into the system
5	Thermal Oxidizer	--	Reduction in acid gas CH_4. Increase in CO_2 due to acid gas combustion	Vendor Data
6	Flare	--	Reduction in acid gas CH_4. Increase in CO_2 due to acid gas, supplemental fuel, and pilot gas combustion.	http://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/flares/ and vendor data

11.1.4. Step 4 – Evaluate Most Effective Control Options

The only technically feasible technology listed in Step 3 that may have additional energy, environmental, and economic impacts is CO_2 Capture and Sequestration.

The exhaust from the amine still vent contains a high concentration of CO_2 (90%) as shown in the ProMax simulation output included in Appendix A; however additional processing of the exhaust gas will be required to implement CCS. The vent gas contains VOC and HAP impurities. The vent gas must undergo separation (removal of other pollutants from gas), capture, and compression. Once the CO_2 stream is treated, it can be controlled from this project in one of the following ways:

- Sequestered in a geological formation
- Use in Enhanced Oil Recovery (EOR)
- Transported to an existing CO_2 pipeline

A study of the risks associated with long-term geologic storage of CO_2 places those risks on par with the underground storage of natural gas or acid-gas[33]. The liability of underground CO_2 storage, however, is less understood. A recent publication from MIT states that "The characteristics (of long term CO_2 storage) pose a challenge to a purely private solution to liability" (de Figueiredo, M., 2007. The Liability of Carbon Dioxide Storage, Ph.D. Thesis, MIT Engineering). Based on the location of the proposed Avalon Mega CGF, there are other demonstrated and cost effective options for CO_2 control; therefore the liability associated with sequestration in geologic formations and long-term environmental impact uncertainty remove this CCS option from further consideration.

The Avalon Mega CGF is approximately 12 miles from the existing Kinder Morgan CO_2 pipeline network. The Kinder Morgan pipeline network provides CO_2 for various uses, including EOR. Therefore the evaluation of transferring the Avalon Mega CGF CO_2 to an existing pipeline network includes both the options of transporting the CO_2 to an existing pipeline and using the gas for EOR. The CO_2 Sales Definition Study conducted by WGM to determine the financial and environmental impacts of implementing CCS through transporting the CO_2 to an existing pipeline network evaluates the financial feasibility of both options.

DBJVG, through the WGM study, reviewed the feasibility to recover CO_2 for use in for enhanced oil recovery in the area or transported via CO_2 pipeline for sale to other users in various parts of the area or state. This study determined that the Avalon Mega CGF is capable of producing 1217 tons (1104 metric tons) of CO_2 at a maximum natural gas production rate of 200 MM SCFD and with a CO_2 level of 11% in the produced gas. For the baseline facility design, the CO_2 is exhausted into the atmosphere through thermal oxidizers to insure all VOC and HAP impurities are destroyed.

The primary purpose of the Avalon Mega CGF amine units is to remove the CO_2 in the acid gas stream to meet the pipeline specification; therefore the amine still vent is a very high CO_2 concentrated stream (90%). While the amine still vent has a high CO_2 content, additional processing of the exhaust gas will be required to meet the specifications of the Kinder Morgan pipeline. These include separation (removal of other pollutants from the vent gases), capture, and compression of CO_2, transfer of the CO_2 stream and sequestration of the CO_2 stream. These processes require additional equipment to reduce the exhaust temperature, compress the gas, and transport the gas via pipelines. Compressing the captured CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall power plant system. Published studies estimate energy penalties in the range of 15% to 30% for CCS. This would also mean that up to 30% more fuel will be consumed, 30% more CO_2 will be produced at the facility, and 30% more criteria pollutant emission (NO_x, CO, VOC, PM, SO_2) would be generated. This would result in significant negative environmental and energy impacts.

Specifically, the amine vent stream must be dehydrated by using a DEG glycol dehydrator to reduce the water content. The water content is the most critical parameter due to the corrosion associated with CO_2 stream with water. The H_2S levels in the natural gas are low, typically expected to be between 4 and 12 ppm for the gas processed at Avalon Mega CGF. The concentrated H_2S levels in the amine unit still vent are expected to range between 40 and 120 ppm. The H_2S will be removed via treating unit using one of several available processes. For this study we have used a Sulfatreat™ catalytic process. Since the H_2S levels are low, the catalyst usage will be low in the Sulfatreat system. The spent catalyst is environmentally safe and can be easily disposed of via landfill or sold for fertilizer. The series of treatment processes would result in a CO_2 product of approximately 99.8%.

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[33] Benson, S. 2006. CARBON DIOXIDE CAPTURE AND STORAGE, Assessment of Risks from Carbon Dioxide Storage in Deep Underground Geological Formations. Lawrence Berkley National Laboratory

The CO_2 will be collected from the Avalon Mega CGF facility in a 4" pipeline and the gathering lines will feed a 6" pipeline. The pipeline will transport the gas to the Kinder Morgan pipeline for transport to market. The collection headers total length is 10 miles. The pipeline is assumed to be 12 miles.

The WGM study determined the total initial capital cost of the equipment and infrastructure required to capture, compress, treat, and transfer the CO_2 to the Kinder Morgan pipeline approximately is $44,065,000.00, with annual operating costs of $1,826,000. These costs were provided in the WGM study in a formal CAPEX Estimate Study for the Avalon Mega CGF project. The overall estimated cost of CCS implementation represents the sum of the individual cost factors. The overall cost of the Avalon Mega CGF project is an initial capital investment of approximately $117,000,000 with annual operating costs of $8,000,000. As shown in Appendix D, the estimated cost of CCS implementation at the Avalon Mega CGF is $17.04/ton removed of CO_2. The total annualized cost of the CCS over a ten year lifespan is approximately $8,083,230 compared to an annualized cost of the project of $24,614,000. The implementation of CCS represents an additional 33% cost to the project on an annual basis. As such, DBJVG contends that CCS is economically infeasible control technology option and eliminates CCS from further review under this BACT analysis.

11.1.5. Step 5 – Select BACT for the Amine Unit Still Vent

DBJVG proposes to utilize a well-designed and operated TO to treat the amine unit acid gas stream. The additional design elements and work practices as BACT for the amine still vent in place of a numerical BACT limit:

- Condenser;
- Use of a Thermal Oxidizer;
- Use of Tank Flash Gas Recovery Systems; and
- Proper Design and Operation.

The TO produces no significant additional GHG emissions beyond what is already present in the acid gas stream. Specific monitoring and work practices for the TO are found in section 11.2.5 of this BACT analysis.

11.2. THERMAL OXIDIZER

Each thermal oxidizer (EPNs: TO-1 through TO-6) at Avalon Mega CGF are designed to destroy, through combustion, the process waste gas produced by the amine units, and has a fuel firing rate of 9 MMBtu/hr when firing natural gas. GHG emissions will be generated by the combustion of natural gas as well as combustion of the vent gas routed to the TO.

CO_2 emissions from burning waste gas are produced from the combustion of carbon-containing compounds (e.g., VOCs, CH_4) present in the vent streams routed to the TO and the burner fuel. CO_2 emissions emitted from the TO are based on the amount of carbon-containing gases produced from the amine unit. In addition, minor amounts of CH_4 emissions are emitted from the TO due to incomplete combustion of CH_4.

The TO is an example of a control device for which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of VOCs, HAPs and specifically CH_4 in the process gas to the TO results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to the waste gas even though it will form additional CO_2 emissions.[34] The TO has a destruction and removal efficiency of a least 99% for VOCs and HAPs.

The following sections present a BACT evaluation for GHG emissions from combustion of burner gas and amine still vent gas released to the TOs.

11.2.1. Step 1 – Identify All Available Control Technologies

The available GHG emission control strategies for the flare that were analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration;
- Proper Design;
- Low Carbon Fuel Selection; and
- Good Combustion, Operating, and Maintenance Practices.

11.2.1.1. Carbon Capture and Sequestration

The viability of CCS has been discussed previously in Section 11.1 and is not considered a viable option at this time. The emission units evaluated in this BACT analysis section are the TO burners only. The employment of CCS for the amine units still vent were deemed economically infeasible as discussed in Section 11.1.4. Therefore controlling these minimal emissions generated from the TO burners is also economically infeasible.

11.2.1.2. Proper Design

Good TO design can be employed to destroy any HAPs, VOCs and CH_4 entrained in the waste gas from the amine unit. Good TO design includes flow measurement and monitoring/control of waste gas heating values.

11.2.1.3. Low Carbon Fuel Selection

The fuel for firing the proposed TOs will be limited to natural gas fuel. Natural gas has the lowest carbon intensity of any available fuel for the TO.

11.2.1.4. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option by improving the fuel efficiency of the TO. Good combustion practices also include proper maintenance and tune-up of the TO at least annually per the manufacturer's specifications as outlined in Table 10.4-2.

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[34] For example, combusting 1 lb of CH_4 (21 lb CO_2e) at the flare will result in 0.02 lb CH_4 and 2.7 lb CO_2 (0.02 lb CH_4 x 21 CO_2e/CH_4 + 2.7 lb CO_2 x 1 CO_2e/CO_2 = 2.9 lb CO_2e), and therefore, on a CO_2e emissions basis, combustion control of CH_4 is preferable to venting the CH_4 uncontrolled.

11.2.2. Step 2 – Eliminate Technically Infeasible Options

As discussed above, the burners are the unit of interest in this section; therefore, the use of CCS is technically infeasible as illustrated in Section 11.1.4.

11.2.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The control options for minimizing GHG emissions from the TO are ranked below:

Rank	Control Technology	Estimated Reduction	Reduction Details	Reference
1	Low Carbon Fuel Selection	28% (Natural Gas Versus No. 2 Fuel Oil)	Reduction in all GHGs.	40 CFR Part 98 Subpart C, Table C-1
2	Proper Design	1% - 10%	Reduction in all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 5.1.1.5 Improved Maintenance
3	Good Combustion, Operating, and Maintenance Practices	1% - 10%	Reduction in all GHGs.	EPA Guidance document "Good Combustion Practices" available at: http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf.

11.2.4. Step 4 – Evaluate Most Effective Control Options

No adverse energy, environmental, or economic impacts are associated with the above-mentioned technically feasible control options.

11.2.5. Step 5 – Select BACT for the TO

DBJVG proposes the following design elements and work practices as BACT for the TO:

- Proper Design;
- Low Carbon Fuel Selection; and
- Good combustion, Operating, and Maintenance Practices.

Compliance with work practices and requested monitoring and recordkeeping requirements are noted below:

- The TOs are designed to combust low-VOC concentration waste gas from the amine vent streams.
- For burner combustion, the natural gas fuel usage (scf) will be recorded using a flow meter.
- Each thermal oxidizer shall have an initial performance test, and annual compliance testing, to verify destruction and removal efficiency (DRE) as represented in the application.
- Waste gas will be sampled and analyzed on an annual basis for composition. The sampled data will be used to calculate GHG emissions to show compliance with the limits specified in this application.
- GHG emissions shall be calculated, on a monthly basis, using equations as demonstrated in this application.
- The flowrate of the waste gas combusted will be measured and recorded using a flow meter.
- Periodic maintenance will help maintain the efficiency of the thermal oxidizer and will be performed at a minimum annually or more frequently as recommended by the manufacturer specifications.
- DBJVG will install a temperature monitor in the combustion chamber to record the combustion temperature.

- DBJVG would like to base the minimum combustion temperature to be determined during the initial performance test. DBJVG will maintain that temperature at all times when processing waste gases from the amine units in the thermal oxidizer to ensure proper destruction and removal efficiency. DBJVG will install and maintain a temperature recording device with an accuracy of ± 0.75 percent of the temperature being measured expressed in degrees Celsius.

11.3. COMPRESSOR ENGINES

GHG emissions from the proposed engines (EPNs: E-01, E-02, E-03, E-04, E-05, E-06, E-07, E-08, E-09, E-10, E-11, and E-12) include CO_2, CH_4 and N_2O and result from the combustion of natural gas. The following section presents BACT evaluations for GHG emissions from the proposed engines.

11.3.1. Step 1 – Identify All Available Control Technologies

The available GHG emission control strategies for the engines that were analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration;
- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;
- Air/fuel ratio controllers; and
- Efficient Engine Design.

11.3.1.1. Carbon Capture and Sequestration

As previously discussed, the contribution of CO_2e emissions from each engine is a fraction of the scale for sources where CCS might ultimately be feasible. Although we believe that it is obvious that CCS is not BACT in this case, as directly supported in EPA's GHG BACT Guidance, a detailed rationale is provided to support this conclusion.

For the engines, CCS would involve post combustion capture of the CO_2 from the engines and sequestration of the CO_2 in some fashion. In general, carbon capture could be accomplished with low pressure scrubbing of CO_2 from the exhaust stream with solvents (e.g., amines and ammonia), solid sorbents, or membranes. However, only solvents have been used to-date on a commercial (yet slip stream) scale and solid sorbents and membranes are only in the research and development phase. A number of post-combustion carbon capture projects have taken place on slip streams at coal-fired power plants. Although these projects have demonstrated the technical feasibility of small-scale CO_2 capture on a slipstream of a power plant's emissions using various solvent based scrubbing processes, until these post-combustion technologies are installed fully on similar engines, they are not considered "available" in terms of BACT.

Larger scale CCS demonstration projects have been proposed through the DOE Clean Coal Power Initiative (CCPI); however, none of these facilities are operating, and, in fact, they have not yet been fully designed or constructed.[35] Additionally, these demonstration projects are for post-combustion capture on a pulverized coal (PC) plant using a slip stream versus the full exhaust stream. Also, the exhaust from a PC plant would have a significantly higher

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35 Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, p. 32.

concentration of CO_2 in the slipstream as compared to a more dilute stream from the combustion of natural gas.[36] In addition, the compression of the CO_2 would require additional power demand, resulting in additional fuel consumption (and CO_2 emissions).[37]

11.3.1.2. Fuel Selection

Natural gas has the lowest carbon intensity of any available fuel for the engines. The proposed engines will be fired with only natural gas fuel.

11.3.1.3. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option by improving the fuel efficiency of the engines. Good combustion practices also include proper maintenance and tune-up of the engine at least annually per the manufacturer's specifications as outlined in Table 10.4-2.

11.3.1.4. Air/fuel ratio controllers

Air/fuel ratio controllers minimize methane emissions from reciprocating engines. Combustion units operated with too much excess air may lead to inefficient combustion, and additional energy will be needed to heat the excess air. Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture and reduce the amount of energy required to heat the stream and, therefore, reduce the CO_2e emissions. Please note because these engines are equipped with the ultra-lean burn technology, air/fuel ratio controllers are inherent to the process in the engines.

11.3.1.5. Efficient Engine Design and Selection

To select the most efficient engine for the Avalon Mega CGF project the following factors were taken into account: site layout square footage, operational fluctuations and flexibility, emissions performance, and energy efficiency.

To meet the compression needs of this project, larger engines with high horsepower ratings are required to move the large amounts of gas at the facility. Engine manufacturers such as Ajax, Cummins, and Arrow do not manufacture engines that could handle the compression needs of the Avalon Mega CGF. The two engine manufacturers with engines large enough to meet the needs of the facility are Waukesha and Caterpillar.

Except for one extremely large engine model that is not readily available in the United States, Waukesha engines generally utilize rich burn technology to burn fuel in the engine combustion chamber. Rich burn is an inherently inefficient combustion process that results in increased fuel usage compared to lean burn engines. Therefore, the Waukesha engines were eliminated from consideration due to their inefficient rich burn design. The engine selection process then focused on energy efficient lean burn technology offered by Caterpillar engines.

Caterpillar manufactures a large engine, the CAT CTM series engine, that is similar in size to the very large lean burn Waukesha engine, but it is also not readily available for this application. In addition, this larger engine does not allow for sufficient operational flexibility in the case of declining fields, shut-in wellsites, and other potential impacts on engine load. Caterpillar offers three engine models that could satisfy all the needs of this project: the G3608LE,

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[36] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, p. A-7.

[37] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf, p. 29

G3612LE, and G3616LE. The "LE" in the model names means low emission, so these engines also have lower levels of criteria pollutants, which meet the criteria PSD-BACT requirements. The following table compares the three available Caterpillar engines evaluated for this project.

Table 11.3-1. Efficiency Comparison of Caterpillar Engines

Model	Horsepower Rating (HP)	# of Engines Required to meet Compression Needs of Avalon Mega CGF	BSFC @ 100%	BSFC @ 50%
G3608LE	2370	19	6791	7785
G3612LE	3550	12	6791	7684
G3616LE	4735	10	6766	7728

The G3616LE engine is slightly more fuel efficient than the G3612LE engine at full load. However, due to the operational concerns mentioned previously, it is more likely that these engines, if used at this facility, would be operating closer to 50% load than 100% load. This would result in a severe increase in fuel consumption for this engine model, and prevent sufficient operational flexibility for the site.

A G3608LE is just as fuel efficient as the G3612LE; however, several more engines would be required for the site to be able to meet its compression needs. This would result in more maintenance costs, more land required, and likely increased lubricating oil consumption as well, which combine to make this engine model a poor choice for this site.

Therefore, due to these factors, the G3612LE is the most optimum solution for a fuel efficient natural gas fired engine. There is insufficient grid capacity for electrical engines to be operated at this facility, and natural gas is a cleaner burning fuel than other sources.

11.3.2. Step 2 – Eliminate Technically Infeasible Options

As discussed below, CCS is deemed technically infeasible for control of GHG emissions from the engines. All other control options are technically feasible.

11.3.2.1. Carbon Capture and Sequestration

The feasibility of CCS is highly dependent on a continuous CO_2-laden exhaust stream, and CCS has not been tested or demonstrated for such small combustion sources. Given the limited deployment of only slipstream/demonstration applications of CCS and the quantity and quality of the CO_2 emissions stream, CCS is not commercially available as BACT for the engines and is therefore infeasible. This is supported by EPA's assertion that CCS is considered "available" for projects that emit CO_2 in "large" amounts.[38] A detailed CCS evaluation was provided in Section 11.1.4

[38] PSD and Title V permitting Guidance for Greenhouse Gases. March 2011, page 32. "For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology[86] that is "available"[87] 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). The proposed project is not any of the cases EPA suggests above.

for the 90% CO_2 stream from the amine still vents. These emission units, by comparison, emit CO_2 in small and more diluted quantities. In addition, the CO_2 concentration in the flue gas stream is approximately 4.6%. Carbon capture could be accomplished with low pressure scrubbing of CO_2 from the exhaust stream with solvents (e.g., amines and ammonia), solid sorbents, or membranes. However, only solvents have been used to-date on a commercial (yet slip stream) scale. The use of solid sorbents and membranes are considered to be in the research and development phase. Implementing CCS on the engine flue gas streams would require considerable additional gas processing equipment to separate the CO_2 from the exhaust. The low purity and concentration of CO_2 in the engines' exhaust means that the per ton cost of removal and storage will be much higher than the public data estimates for much larger carbon rich fossil fuel facilities due to the loss of economies of scale. Even using low-side published estimates for CO_2 capture and storage of $256 per ton for equipment with similar flue gas characteristics such as a new natural gas combined cycle turbine, assuming a conservative $6/MBtu gas price (Anderson, S., and Newell, R. 2003. Prospects for Carbon Capture and Storage Technologies. Resources for the Future. Washington DC) means added cost to the project over $42,059,654 per year. The equipment to treat the engine exhaust to separate the CO_2 would cost as much as all the treatment equipment and pipeline required for only the amine still vents. Therefore, CCS is not considered a technically, economically, or commercially viable control option for the proposed process heaters. CCS is not considered as a control option for further analysis.

11.3.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

With elimination of CCS as a control option, the following remain as technically feasible control options for minimizing GHG emissions from the engines:

- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;
- Air/fuel ratio controllers; and
- Efficient Engine Design.

Since DBJVG proposes to implement all of these control options, ranking these control options is not necessary.

11.3.4. Step 4 – Evaluate Most Effective of Control Options

No adverse energy, environmental, or economic impacts are associated with the above-mentioned technically feasible control options.

11.3.5. Step 5 – Select BACT for the Engines

DBJVG proposes the following design elements and work practices as BACT for the engines:

- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;
- Air/fuel ratio controllers; and
- Efficient Engine Design.

DBJVG proposes the CO_2e emission limits for the engines:

- For each engine (EPNs: E-01, E-02, E-03, E-04, E-05, E-06, E-07, E-08, E-09, E-10, E-11, and E-12): 13,705 short tons of CO_2e per year per engine

These proposed emission limits are based on a 12-month rolling average basis and include CO_2, CH_4, and N_2O emissions, with CO_2 emissions being more than 99% of the total emissions.

Compliance with these emission limits will be demonstrated by monitoring fuel consumption and performing calculations consistent with the calculations included in Appendix C of this application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average short tons of CO_2e per year emission rates do not exceed these limits.

Compliance with the requested BACT limits will be demonstrated through the following operational, monitoring and recordkeeping requirements:

- All compressor engines will be equipped with lean-burn with low NO_x technology and oxidation catalysts, and will be operated using good combustion practices.
- All engines will be tuned once per year, or more frequently, per manufacturer recommendations.
- CO_2 emitted from the engines will be calculated on a monthly basis using equation C-2a in 40 CFR Part 98 Subpart C.
- CH_4 and N_2O emissions will be calculated on a monthly basis using the default CH_4 and N_2O emission factors contained in Table C-2, equation C-9a of 40 CFR Part 98, and the measured actual heat input (HHV).
- The CO_2e emissions will be calculated on a 12-month rolling average, based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on October 30, 2009 (74 FR 56395).
- Fuel for the Compressor Engines shall be limited to natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf).
- The high heat value (HHV) of the fuel shall be determined, at a minimum, semiannually by the procedures contained in 40 CFR Part 98.34(a)(6).
- The fuel combusted in the compressor engines will be measured and recorded using an operational nonresettable elapsed flow meter. Flow meters will be calibrated annually.

11.4. AMINE AND TEG DEHYDRATOR REBOILERS

GHG emissions from the proposed reboilers (EPNs: H-01 through H-06 and RB-1 through RB-6) include CO_2, CH_4 and N_2O and result from the combustion of natural gas. The reboilers include the six amine unit and six TEG dehydrator reboilers. The following section presents BACT evaluations for GHG emissions from the proposed reboilers.

11.4.1. Step 1 – Identify All Available Control Technologies

The available GHG emission control strategies for the reboilers that were analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration;
- Low Carbon Fuel Selection;
- Good Combustion, Operating, and Maintenance Practices;
- Combustion Air Controls;
- Fuel Gas Pre-heater/Air Pre-heater; and
- Efficient Heater Design.

11.4.1.1. Carbon Capture and Sequestration

As previously discussed, the contribution of CO_2e emissions from each reboiler is a fraction of the scale for sources where CCS might ultimately be feasible. Although we believe that it is obvious that CCS is not BACT in this case, as directly supported in EPA's GHG BACT Guidance, a detailed rationale is provided to support this conclusion.

For each reboiler, CCS would involve post combustion capture of the CO_2 from the reboiler stack and sequestration of the CO_2 in some fashion. In general, carbon capture could be accomplished with low pressure scrubbing of CO_2 from the exhaust stream with solvents (e.g., amines and ammonia), solid sorbents, or membranes. However, only solvents have been used to-date on a commercial (yet slip stream) scale and solid sorbents and membranes are only in the research and development phase. A number of post-combustion carbon capture projects have taken place on slip streams at coal-fired power plants. Although these projects have demonstrated the technical feasibility of small-scale CO_2 capture on a slipstream of a power plant's emissions using various solvent based scrubbing processes, until these post-combustion technologies are installed on similar equipment, they are not considered "available" in terms of BACT.

Larger scale CCS demonstration projects have been proposed through the DOE Clean Coal Power Initiative (CCPI); however, none of these facilities are operating, and, in fact, they have not yet been fully designed or constructed.[39] Additionally, these demonstration projects are for post-combustion capture on a pulverized coal (PC) plant using a slip stream versus the full exhaust stream. Also, the exhaust from a PC plant would have a significantly higher concentration of CO_2 in the slipstream as compared to a more dilute stream from the combustion of natural gas.[40] In addition, the compression of the CO_2 would require additional power demand, resulting in additional fuel consumption (and CO_2 emissions).[41]

11.4.1.2. Low Carbon Fuel Selection

Natural gas has the lowest carbon intensity of any available fuel for the reboilers. The proposed reboilers will be fired with only natural gas fuel.

11.4.1.3. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option by improving the fuel efficiency of the reboilers. Good combustion practices also include proper maintenance and tune-up of the process heaters at least annually per the manufacturer's specifications as outlined in Table 10.4-2.

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[39] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, p. 32.

[40] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, p. A-7.

[41] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf, p. 29

11.4.1.4. *Combustion Air Controls*

Combustion units operated with too much excess air may lead to inefficient combustion, and additional energy will be needed to heat the excess air. Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture. [42]

11.4.1.5. *Fuel Gas Pre-heater / Air Pre-heater*

Preheating the fuel gas and air reduces heating load and increases thermal efficiency of the combustion unit. An air pre-heater recovers heat in the heater exhaust gas to preheat combustion air. Preheating the combustion air in this way reduces heater heating load, increases its thermal efficiency, and reduces emissions.

11.4.1.6. *Efficient Heater Design*

Efficient design and proper air-to-fuel ratio improve mixing of fuel and create more efficient heat transfer. Since DJBVG is proposing to install new equipment, these reboilers will be designed to optimize combustion efficiency. Additionally, the amine units and TEG dehydrator have been designed to minimize heat duty and require less fuel to treat inlet gas.

11.4.2. Step 2 – Eliminate Technically Infeasible Options

As discussed below, CCS and fuel gas/air preheating are deemed technically infeasible for control of GHG emissions from the process heaters. All other control options are technically feasible.

11.4.2.1. *Carbon Capture and Sequestration*

The feasibility of CCS is highly dependent on a continuous CO_2-laden exhaust stream, and CCS has not been tested or demonstrated for such small combustion sources. Given the limited deployment of only slipstream/demonstration applications of CCS and the quantity and quality of the CO_2 emissions stream, CCS is not commercially available as BACT for the process heaters and is therefore infeasible. This is supported by EPA's assertion that CCS is considered "available" for projects that emit CO_2 in "large" amounts.[43] This project and these emission units, by comparison, emit CO_2 in small quantities. Therefore, CCS is not considered a technically, economically, or commercially viable control option for the proposed process heaters. CCS is not considered as a control option for further analysis.

11.4.2.2. *Fuel Gas Pre-heater / Air Pre-heater*

Fuel gas/air preheating is not feasible for small heaters. This is more suitable for large boilers (>100 MMBtu/hr). In addition, these options may increase NO_X emissions.

[42] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, U.S. EPA, October 2010, Section 3.

[43] *PSD and Title V permitting Guidance for Greenhouse Gases*. March 2011, page 32. *"For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology[86] that is "available"[87] 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).* The proposed project is not any of the cases EPA suggests above.

11.4.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

With elimination of CCS and fuel gas/air preheating as control options, the following remain as technically feasible control options for minimizing GHG emissions from the process heaters:

Rank	Control Technology	Estimated Reduction	Reduction Details	Reference
1	Low Carbon Fuel Selection	28% (Natural Gas Versus No. 2 Fuel Oil)	Reduction in all GHGs.	40 CFR Part 98 Subpart C, Table C-1
2	Efficient Heater Design	10%	Reduction in all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 3.0 Summary of GHG Reduction Measures Table 1 Summary of GHG Reduction Measures for the Petroleum Refinery Industry
3	Good Combustion, Operating, and Maintenance Practices	1% - 10%	Reduction in all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 5.1.1.5 Improved Maintenance
4	Combustion Air Controls	1% - 3%	Reduction in all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 3.0 Summary of GHG Reduction Measures Table 1 Summary of GHG Reduction Measures for the Petroleum Refinery Industry

11.4.4. Step 4 – Evaluate Most Effective of Control Options

No adverse energy, environmental, or economic impacts are associated with the above-mentioned technically feasible control options.

11.4.5. Step 5 – Select BACT for the Reboilers

DBJVG proposes the following design elements and work practices as BACT for the process heaters:

- Low Carbon Fuel Selection;
- Efficient Heater Design;
- Good Combustion, Operating, and Maintenance Practices; and
- Combustion Air Controls.

DJVBG proposes the combined CO_2 emission limit, expressed in lb CO_2/MMscf, for each train that contains one amine and one TEG dehydrator reboiler as follows:

EPN	Description	Proposed BACT Limit
H-01 and RB-01	Train 1	3,822 lb CO_2/MMscf
H-02 and RB-02	Train 2	3,822 lb CO_2/MMscf
H-03 and RB-03	Train 3	3,822 lb CO_2/MMscf
H-04 and RB-04	Train 4	3,822 lb CO_2/MMscf
H-05 and RB-05	Train 5	3,822 lb CO_2/MMscf
H-06 and RB-06	Train 6	3,822 lb CO_2/MMscf

Where:

$$\left(4{,}676\frac{lb}{hr}+175\frac{lb}{hr}\right)\div 30.461\frac{MMscf}{day}\times 24\frac{hr}{day}=3{,}822\frac{CO_2e \quad lb}{MMscf}$$

These proposed emission limits are based on the plant design outlet flowrate of 30.461 MMSCFD per train and the maximum potential to emit (lb/hr) of the amine unit and TEG dehydrator reboilers.

Compliance with these emission limits will be demonstrated by monitoring plant inlet volume and performing calculations consistent with the calculations included in Appendix C of this application.

Compliance with the requested BACT limits demonstrated through the following operational, monitoring and recordkeeping requirements:

- CO_2 emitted from the engines will be calculated on a monthly basis using equation C-2a in 40 CFR Part 98 Subpart C.
- CH_4 and N_2O emissions will be calculated on a monthly basis using the default CH_4 and N_2O emission factors contained in Table C-2 and equation C-9a of 40 CFR Part 98 and the measured actual heat input (HHV).
- The CO_2e emissions will be calculated on a 12-month rolling average, based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on October 30, 2009 (74 FR 56395).
- The high heat value (HHV) of the fuel shall be determined, at a minimum, semiannually by the procedures contained in 40 CFR Part 98.34(a)(6).
- The fuel combusted in the reboilers will be measured and recorded using an operational nonresettable elapsed flow meter. Flow meters will be calibrated annually.
- The reboilers will be tuned for thermal efficiency on an annual basis.

11.5. FLARES

The flares at the Avalon Mega CGF will be used to destroy the off-gas produced during emergency situations and during planned MSS activities. GHG emissions will be generated by the combustion of natural gas as well as combustion of the vent gas to the flare.

CO_2 emissions from flaring process gas are produced from the combustion of carbon-containing compounds (e.g., VOCs, CH_4) present in the vent streams routed to the flare during MSS events and the pilot fuel. CO_2 emissions from the flare are based on the estimated flared carbon-containing gases derived from heat and material balance data. In addition, minor CH_4 emissions from the flare are emitted from the flare due to incomplete combustion of CH_4.

The flares are an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of CH_4 in the process gas at the flare results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions.[44]

The following sections present a BACT evaluation for GHG emissions from combustion of pilot gas.

11.5.1. Step 1 – Identify All Available Control Technologies

The available GHG emission control strategies for the flares that were analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration;
- Low Carbon Fuel Selection;
- Flare Gas Recovery;
- Good Combustion, Operating, Maintenance Practices; and
- Good Flare Design.

11.5.1.1. Carbon Capture and Sequestration

A detailed discussion of CCS technology is provided in Section 11.1.

11.5.1.2. Low Carbon Fuel Selection

The pilot gas fuel for the proposed flare will be limited to natural gas fuel. Natural gas has the lowest carbon intensity of any available fuel.

11.5.1.3. Flare Gas Recovery

Flaring can be reduced by installation of commercially available recovery systems, including recovery compressors and collection and storage tanks. The recovered gas is then utilized by introducing it into the fuel system as applicable.

11.5.1.4. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option for improving the combustion efficiency of the flare. Good combustion practices include proper operation, maintenance, and tune-up of the flare at least annually per the manufacturer's specifications.

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[44] For example, combusting 1 lb of CH_4 (21 lb CO_2e) at the flare will result in 0.02 lb CH_4 and 2.7 lb CO_2 (0.02 lb CH_4 x 21 CO_2e/CH_4 + 2.7 lb CO_2 x 1 CO_2e/CO_2 = 2.9 lb CO_2e), and therefore, on a CO_2e emissions basis, combustion control of CH_4 is preferable to venting the CH_4 uncontrolled.

11.5.1.5. Good Flare Design

Good flare design can be employed to destroy large fractions of the flare gas. Much work has been done by flare and flare tip manufacturers to assure high reliability and destruction efficiencies. Good flare design includes pilot flame monitoring, flow measurement, blower controls, and monitoring/control of waste gas heating value.

11.5.2. Step 2 – Eliminate Technically Infeasible Options

The technical infeasibility of CCS and flare gas recovery is discussed below. All other control technologies listed in Step 1 are considered technically feasible.

11.5.2.1. Carbon Capture and Sequestration

With no ability to collect exhaust gas from a flare other than using an enclosure, post combustion capture is not an available control option. Pre-combustion capture has not been demonstrated for removal of CO_2 from intermittent process gas streams routed to a flare. Flaring will be limited to emergency situations and during planned startup and shutdown events of limited duration and vent rates resulting in a very intermittent CO_2 stream; thus, CCS is not considered a technically feasible option. Therefore, it has been eliminated from further consideration in the remaining steps of the analysis.

11.5.2.2. Flare Gas Recovery

Installing a flare gas recovery system to recover flare gas to the fuel gas system is considered a feasible control technology for industrial process flares. Flaring at Avalon Mega CGF will be limited to emergency situations and during planned startup and shutdown events of limited duration and vent rates. Due to infrequent MSS activities and the amount of gas sent to the flare, it is technically infeasible to re-route the flare gas to a process fuel system and hence, the gas will be combusted by the flare for control. Therefore, the amount of flare gas produced by this project will not sustain a flare gas recovery system. For this project, flare gas recovery is infeasible.

11.5.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

With elimination of CCS and flare gas recovery as technically infeasible control options, the following control options remain as technically feasible control options for minimizing GHG emissions from the flare:

Rank	Control Technology	Estimated Reduction	Reduction Details	Reference
1	Low Carbon Fuel Selection	28% (Natural Gas Versus No. 2 Fuel Oil)	Reduction in all GHGs.	40 CFR Part 98 Subpart C, Table C-1
2	Good Flare Design	1% - 15%	Reduction in all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 3.0 Summary of GHG Reduction Measures Table 1 Summary of GHG Reduction Measures

				for the Petroleum Refinery Industry
3	Good Combustion, Operating, Maintenance Practices	1% - 10%	Reduction in all GHGs.	EPA Guidance document "Good Combustion Practices" available at: http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf.

11.5.4. Step 4 – Evaluate Most Effective Control Options

No significant adverse energy or environmental impacts (that would influence the GHG BACT selection process) associated with the above-mentioned technically feasible control options are expected.

11.5.5. Step 5 – Select BACT for the Flares

DJBVG proposes the following design elements and work practices as BACT for the flare:

- Low Carbon Fuel Selection;
- Good Combustion, Operating, Maintenance Practices; and
- Good Flare Design.

The flare will meet the requirements of 40 CFR §60.18, and will be properly instrumented and controlled. Compliance with work practices is noted below:

- Flare shall have a minimum destruction and removal efficiency (DRE) of 98% based on flowrate and gas composition measurements as specified in 40 CFR Part 98 Subpart W §98.233(n).
- The flare shall be designed and operated in accordance with 40 CFR 60.18 including specifications of minimum heating value of the waste gas, maximum tip velocity, and pilot flame monitoring.
- An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes.
- DBJVG proposes to limit MSS activities and flaring events to minimize GHG emissions from this source.
- DBJVG proposes the implementation of good combustion practices noted in their initial application.

11.6. EMERGENCY GENERATORS

The proposed project will comprise six 1214-bhp diesel fired emergency generators. The emergency generators will be limited to 100 hours of operation per year for purposes of maintenance and testing. CO_2 emissions from the diesel engines are produced from the combustion of hydrocarbons present in the diesel fuel. CH_4 emissions result from incomplete combustion of hydrocarbons present in the diesel fuel. N_2O emissions from diesel-fueled units form solely as a byproduct of combustion. The engines are designed to use diesel fuel, stored in onsite tanks, so that emergency power is available for safe shutdown of the facility in the event of a power outage or natural gas supply curtailments.

The following sections present a BACT evaluation of GHG emissions from the emergency generator engines.

11.6.1. Step 1 - Identify All Available Control Technologies

The available GHG emission control strategies for emergency generators that were analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration;

- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;

11.6.1.1. Carbon Capture and Sequestration

CCS is not considered an available control option for emergency equipment that operates on an intermittent basis and must be immediately available during plant emergencies without the constraint of starting up the CCS process.

11.6.1.2. Fuel Selection

The only technically feasible fuel for the emergency generators is diesel fuel. While natural gas-fueled emergency generators may provide lower GHG emissions per unit of power output, natural gas is not considered a technically feasible fuel for the emergency generators since they will need to be used in the event of an emergency, when natural gas supplies may be interrupted.

11.6.1.3. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices, as specified in Table 10.4-2, are a potential control option for maintaining the combustion efficiency of the emergency equipment. Good combustion practices include proper maintenance and tune-up of the emergency engines at least annually per the manufacturer's specifications.

11.6.2. Step 2 - Eliminate Technically Infeasible Options

Due to the fact that the emergency generators will operate less than 100 hours per year in non-emergency service, and because their stack gases are low in volume and CO_2 mass rate, capture and segregation of CO_2 for sequestration has not been demonstrated. Therefore, it has been eliminated from further consideration in the remaining steps of the analysis. As explained above, the only technically feasible fuel for the emergency generators is diesel fuel. All other control technologies are considered feasible.

11.6.3. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

DBJVG will select emergency generators with high fuel combustion efficiency and will implement good combustion, operating, and maintenance practices to minimize GHG emissions.

11.6.4. Step 4 - Evaluate Most Effective Control Options

No adverse energy, environmental, or economic impacts are associated with the above-mentioned technically feasible control options.

11.6.5. Step 5 - Select CO_2 BACT for Emergency Generators

Based on the selection of a fuel efficient emergency generators and implementing good combustion, operating and maintenance practices as described in Table 10.4-2, DBJVG will meet BACT through work practices. Further, these new engines will be subject to the federal New Source Performance Standard (NSPS) for Stationary Compression Ignition Internal Combustion Engines (40 CFR Part 60, Subpart IIII), such that specific emissions standards for various pollutants must be met during normal operation, such that the engines will meet or exceed BACT.

11.7. FUGITIVE COMPONENTS

The following sections present a BACT evaluation of fugitive CO_2 and CH_4 emissions. It is anticipated that the fugitive emission controls presented in this analysis will provide similar levels of emission reduction for both CO_2 and CH_4. Fugitive components included in the proposed project include traditional components such as valves and flanges.

11.7.1. Step 1 - Identify All Available Control Technologies

In determining whether a technology is available for controlling GHG emissions from fugitive components, permits and permit applications and EPA's RBLC were consulted. Based on these resources, the following available control technologies were identified and are discussed below:

- Installing leakless technology components to eliminate fugitive emission sources;
- Installing air-driven pneumatic controllers;
- Implementing various LDAR programs in accordance with applicable state and federal air regulations;
- Implementing an alternative monitoring program using a remote sensing technology such as infrared camera monitoring;
- Implementing an audio/visual/olfactory (AVO) monitoring program for odorous compounds; and
- Designing and constructing facilities with high quality components and materials of construction compatible with the process.

11.7.1.1. Leakless Technology Components

Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used. These technologies are generally considered cost prohibitive except for specialized service. Some leakless technologies, such as bellows valves, if they fail, cannot be repaired without a unit shutdown which often generates additional emissions.

11.7.1.2. Air-Driven Pneumatic Controllers

Air-driven pneumatic controllers utilize compressed air and therefore do not emit any GHG emissions.

11.7.1.3. LDAR Programs

Instrumented monitoring is effective for identifying leaking CH_4, and although it cannot detect CO_2, it can detect CO_2 if it is a minor component in a highly concentrated hydrocarbon stream. With CH_4 having a global warming potential greater than CO_2, instrumented monitoring of the fuel and feed systems for CH_4 would be an effective method for control of GHG emissions. Quarterly instrumented monitoring with a leak definition of 500 ppmv (2,000 ppmv for pumps and compressors), accompanied by intense directed maintenance, is generally assigned a control effectiveness of 97% (85% for pumps and compressors). [45] The following table demonstrated the control efficiencies for TCEQ's various LDAR Programs:

Table 11.6-1. TCEQ Control Efficiencies for LDAR Programs

[45] TCEQ published BACT guidelines for fugitive emissions in the document *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.*

Equipment/Service	28M	28RCT	28VHP	28MID	28LAER	AVO
Valves						
Gas/Vapor	75%	97%	97%	97%	97%	97%
Light Liquid	75%	97%	97%	97%	97%	97%
Heavy Liquid	0%	0%	0%	0%	0%	97%
Pumps						
Light Liquid	75%	75%	85%	93%	93%	93%
Heavy Liquid	0%	0%	0%	0%	0%	93%
Flanges/Connectors						
Gas/Vapor	30%	30%	30%	30%	97%	97%
Light Liquid	30%	30%	30%	30%	97%	97%
Heavy Liquid	30%	30%	30%	30%	30%	97%
Compressors	75%	75%	85%	95%	95%	95%
Relief Valves (Gas/Vapor)	75%	97%	97%	97%	97%	97%
Open-ended Lines	75%	97%	97%	97%	97%	97%
Sampling Connections	75%	97%	97%	97%	97%	97%

11.7.1.4. Alternative Monitoring Program

Alternate monitoring programs such as remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons.

11.7.1.5. AVO Monitoring Program

Leaking fugitive components can be identified through AVO methods. The fuel gases and process fluids in the piping components are expected to have discernible odor, making them detectable by olfactory means. A large leak can be detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are common and in place in industry.

11.7.1.6. High Quality Components

A key element in the control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. For example, a valve that has been manufactured under high quality conditions can be expected to have lower runout on the valve stem, and the valve stem is typically polished to a smoother surface. Both of these factors greatly reduce the likelihood of leaking.

11.7.2. Step 2 - Eliminate Technically Infeasible Options

Recognizing that leakless technologies have not been universally adopted as LAER or BACT, even for toxic or extremely hazardous services, it is reasonable to state that these technologies are impractical for control of GHG emissions whose impacts have not been quantified. Any further consideration of available leakless technologies for GHG controls is unwarranted.

All other control options are considered technically feasible.

11.7.3. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

11.7.3.1. Air-Driven Pneumatic Controllers

Installing air-driven pneumatic controllers will result in no GHG emissions to the atmosphere.

11.7.3.2. LDAR Programs

A small amount of GHG may be emitted via piping equipment leaks (i.e., due to CO_2 and methane in the gas streams). It is infeasible to capture GHG emissions from fugitive sources such as piping leaks. However, fugitive GHG emissions can be reduced by utilizing a leak detection and repair (LDAR) program. There are many structured LDAR programs that have been developed as part of state and federal rulemaking and BACT.

LDAR programs are designed to control VOC emissions and vary in stringency. LDAR is currently only required for VOC sources. Methane is not considered a VOC, so LDAR is not required for streams containing a high content of methane.

The TCEQ published BACT guidelines for fugitive emissions in the document *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000*. Table 5 displays the State BACT recommendations based on the uncontrolled fugitive emission rates.

Table 11.6-2. TCEQ BACT Summary for Fugitive VOC Emissions

Uncontrolled Annual Fugitive VOC Emission Rate	Best Available Control Technology
< 10 tpy	May not require monitoring
10 tpy ≤ x < 25 tpy	28M
≥ 25 tpy	28VHP

The uncontrolled VOC annual fugitive emissions are greater than 25 tpy for the Avalon Mega CGF and therefore, the selection of the TCEQ's 28VHP program is the minimum required for VOC BACT.

Instrumented monitoring is effective for identifying leaking CH_4, but may be wholly ineffective for finding leaks of CO_2. With CH_4 having a global warming potential greater than CO_2, instrumented monitoring of the fuel and feed systems for CH_4 would be an effective method for control of GHG emissions. Quarterly instrumented monitoring with a leak definition of 500 ppmv (2,000 ppmv for pumps and compressors), accompanied by intense directed maintenance, is generally assigned a control effectiveness of 97% (85% for pumps and compressors). [46]

11.7.3.3. Alternative Monitoring Program

Remote sensing using infrared imaging has proven effective for identification of leaks including CO_2. The process has been the subject of EPA rulemaking as an alternative monitoring method to the EPA's Method 21. Effectiveness is likely comparable to EPA Method 21 when cost is included in the consideration.

11.7.3.4. AVO Monitoring Program

Audio/Visual/Olfactory means of identifying leaks owes its effectiveness to the frequency of observation opportunities. Those opportunities arise as operating technicians make rounds, inspecting equipment during those routine tours of the operating areas. This method cannot generally identify leaks at a low leak rate as instrumented reading can identify; however, low leak rates have lower potential impacts than do larger leaks. This method, due to frequency of observation is effective for identification of larger leaks.

11.7.3.5. High Quality Components

Use of high quality components is effective in preventing emissions of GHGs, relative to use of lower quality components.

11.7.4. Step 4 - Evaluate Most Effective Control Options

No adverse energy, environmental, or economic impacts are associated with the above-mentioned technically feasible control options.

11.7.5. Step 5 - Select BACT for Fugitive Emissions

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane and CO_2. The total estimated fugitive CO_2 and methane emissions as CO_2e have a very minor contribution to the proposed facility's total GHG emissions. DBJVG will be implementing the 28MID LDAR program to minimize emissions from piping fugitive leaks. While this operational practice is designed to reduce VOC emissions, it has a collateral effect on GHG emissions.

DBJVG evaluated the existing LDAR programs for the purpose of the control of fugitive VOC emissions. Table 11.6-1 is a summary of the TCEQ's LDAR programs and the control efficiencies that may be achieved with each. The selection of the 28 MID LDAR program was considered appropriate to meet the requirements of the project. As shown in Table 11.6-1, the 28LAER LDAR program is one of the TCEQ's most stringent LDAR programs, developed to satisfy LAER requirements in ozone non-attainment areas. The project is located in Loving County, currently classified as being attainment/unclassified for all criteria pollutants. As such, the use of the 28LAER LDAR program was not appropriate.

In addition, DBJVG proposes to run on compressed air for instrument control. No process gas will be utilized or vented for these applications. Additionally, DBJVG will monitor flanges using quarterly OVA monitoring at the same leak

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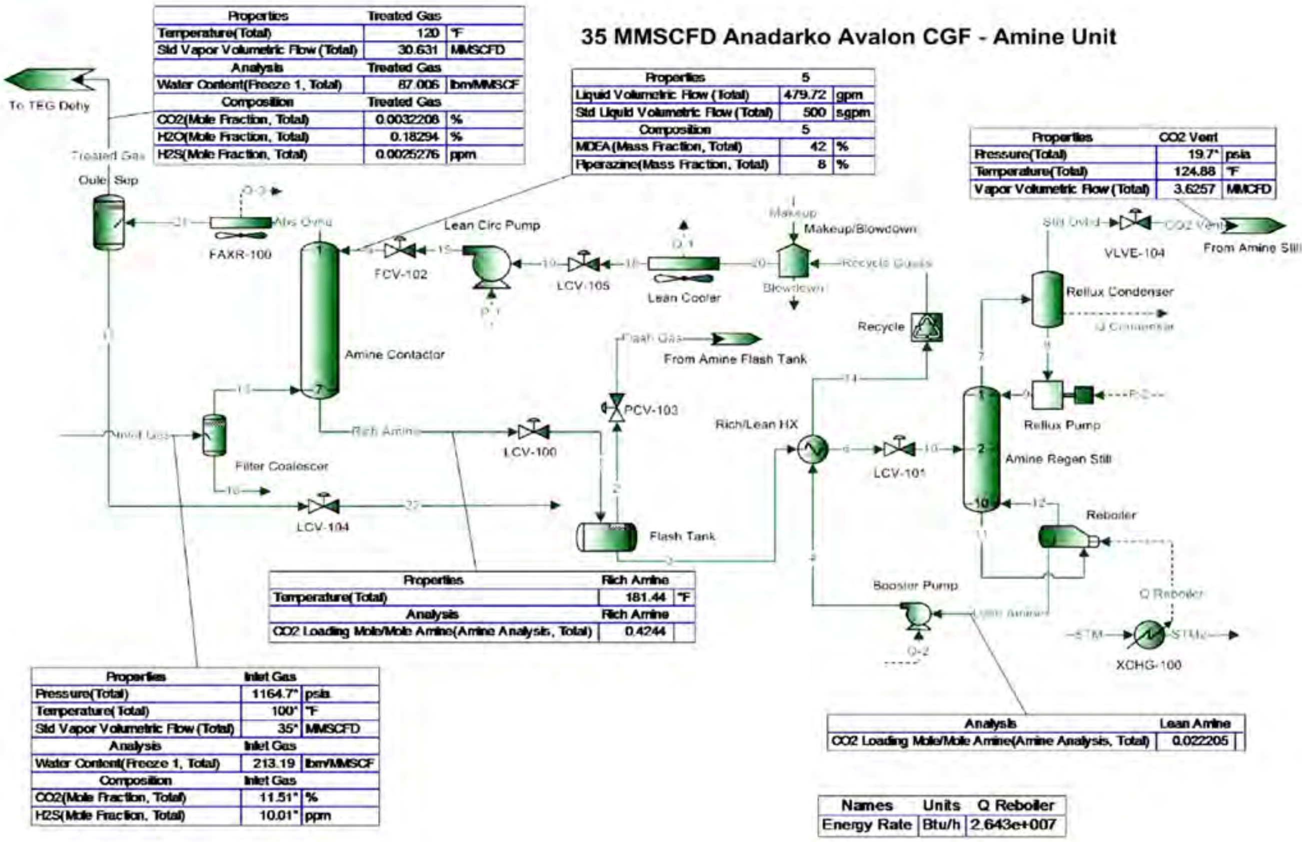
[46] TCEQ published BACT guidelines for fugitive emissions in the document *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.*

definition for valves, resulting in the same control efficiency applied to flanges as is applied to valves. DBJVG will utilize an AVO program to monitor for leaks in between instrumented checks. The proposed project will also utilize high-quality components and materials of construction, including gasketing, that are compatible with the service in which they are employed.

DBJVG is not proposing a numerical BACT limit on GHG emissions from fugitive components since fugitive emissions are estimates only.

PROMAX® Simulation Output

35 MMSCFD Anadarko Avalon CGF - Amine Unit



Properties	Treated Gas	
Temperature(Total)	120	°F
Std Vapor Volumetric Flow (Total)	30.631	MMSCFD
Analysis	Treated Gas	
Water Content(Freeze 1, Total)	87.005	lbm/MMSCF
Composition	Treated Gas	
CO2(Mole Fraction, Total)	0.0032208	%
H2O(Mole Fraction, Total)	0.18294	%
H2S(Mole Fraction, Total)	0.0025276	ppm

Properties	5	
Liquid Volumetric Flow (Total)	479.72	gpm
Std Liquid Volumetric Flow (Total)	500	sgpm
Composition	5	
MDEA(Mass Fraction, Total)	42	%
Piperazine(Mass Fraction, Total)	8	%

Properties	CO2 Vent	
Pressure(Total)	19.7*	psia
Temperature(Total)	124.88	°F
Vapor Volumetric Flow (Total)	3.6257	MMCFD

Properties	Rich Amine	
Temperature(Total)	181.44	°F
Analysis	Rich Amine	
CO2 Loading Mole/Mole Amine(Amine Analysis, Total)	0.4244	

Properties	Inlet Gas	
Pressure(Total)	1164.7*	psia
Temperature(Total)	100*	°F
Std Vapor Volumetric Flow (Total)	35*	MMSCFD
Analysis	Inlet Gas	
Water Content(Freeze 1, Total)	213.19	lbm/MMSCF
Composition	Inlet Gas	
CO2(Mole Fraction, Total)	11.51*	%
H2S(Mole Fraction, Total)	10.01*	ppm

Analysis	Lean Amine
CO2 Loading Mole/Mole Amine(Amine Analysis, Total)	0.022205

Names	Units	Q Reboiler
Energy Rate	Btu/h	2.643e+007

Process Streams		To Thermal Oxidizer	1	2	3	4
Composition	Status:	Solved	Solved	Solved	Solved	Solved
Phase: Total	From Block:	MIX-100	From Amine Flash Tank	From Amine Still	From Glycol Flash Tank	From Glycol Still Vent
	To Block:	--	MIX-100	MIX-100	MIX-100	MIX-100
Mass Fraction		%	%	%	%	%
H2O		10.3553	10.9085	9.49484	0.554138	35.9227
N2		0.0345614	0.185745	0.000114708	0.267659	0.721918
CO2		83.7502	32.9674	90.3304	0.0160488	0.00276046
H2S		0.00727027	0.00243244	0.00786953	2.69607E-06	8.22996E-07
C1		4.68150	46.1690	0.123352	62.1990	50.6693
C2		0.670837	6.57193	0.0304932	16.4604	5.89653
C3		0.269415	2.12669	0.00874517	10.3670	2.91980
iC4		0.0309403	0.206090	0.000739009	1.30335	0.400189
nC4		0.0880801	0.606430	0.00283051	3.84786	1.06057
iC5		0.0224782	0.0658097	0.000127609	1.30248	0.413070
nC5		0.0296215	0.101196	0.000272503	1.62772	0.526135
nC6		0.0245413	0.0564729	0.000148575	1.15017	0.518810
nC7		0.0142966	0.0109513	1.43399E-05	0.499618	0.370632
nC8		0.0118829	0.00858853	1.65010E-05	0.280084	0.328115
nC9		0.00884087	0.0102446	5.61792E-05	0.122871	0.247590
MDEA		0.000182361	0.00223409	2.75698E-13	1.28678E-05	0.00162203
TEG		3.14808E-06	0	0	0.000709080	1.21597E-06
Piperazine		3.20890E-05	0.000327283	5.65714E-14	0.000830195	0.000293985
Mass Flow		lb/h	lb/h	lb/h	lb/h	lb/h
H2O		983.422	61.3121	816.544	0.230853	105.335
N2		5.10380	1.62339	0.0153395	0.173390	3.29168
CO2		19429.8	452.661	18977.1	0.0163329	0.0197738
H2S		1.30617	0.0258640	1.28030	2.12480E-06	4.56533E-06
C1		395.907	231.080	9.44644	23.0744	132.306
C2		106.334	61.6530	4.37697	11.4455	28.8589
C3		62.6260	29.2578	1.84083	10.5712	20.9562
iC4		9.47989	3.73715	0.205042	1.75179	3.78591
nC4		26.9871	10.9968	0.785338	5.17175	10.0333
iC5		8.54923	1.48136	0.0439502	2.17308	4.85084
nC5		11.2661	2.27789	0.0938536	2.71573	6.17859
nC6		11.1485	1.51833	0.0611197	2.29205	7.27705
nC7		7.55172	0.342359	0.00685917	1.15769	6.04481
nC8		7.15541	0.306080	0.00899777	0.739843	6.10048
nC9		5.97732	0.409932	0.0343954	0.364418	5.16857
MDEA		0.114553	0.0830578	1.56828E-10	3.54585E-05	0.0314601
TEG		0.00249215	0	0	0.00246243	2.97220E-05
Piperazine		0.0145705	0.00879524	2.32611E-11	0.00165363	0.00412165

Molar Flow	lbmol/h	lbmol/h	lbmol/h	lbmol/h	lbmol/h
H2O	54.5882	3.40334	45.3251	0.0128143	5.84699
N2	0.182191	0.0579506	0.000547577	0.00618955	0.117504
CO2	441.492	10.2855	431.206	0.000371123	0.000449309
H2S	0.0383255	0.000758900	0.0375664	6.23459E-08	1.33956E-07
C1	24.6787	14.4043	0.588840	1.43834	8.24724
C2	3.53634	2.05038	0.145564	0.380642	0.959754
C3	1.42023	0.663508	0.0417464	0.239734	0.475244
iC4	0.163103	0.0642982	0.00352777	0.0301397	0.0651371
nC4	0.464317	0.189201	0.0135118	0.0889807	0.172624
iC5	0.118494	0.0205320	0.000609161	0.0301195	0.0672338
nC5	0.156150	0.0315721	0.00130083	0.0376407	0.0856368
nC6	0.129370	0.0176190	0.000709248	0.0265975	0.0844446
nC7	0.0753650	0.00341670	6.84535E-05	0.0115535	0.0603263
nC8	0.0626411	0.00267954	7.87699E-05	0.00647687	0.0534060
nC9	0.0466049	0.00319623	0.000268180	0.00284135	0.0402992
MDEA	0.000961323	0.000697015	1.31609E-12	2.97565E-07	0.000264011
TEG	1.65952E-05	0	0	1.63973E-05	1.97919E-07
Piperazine	0.000169158	0.000102109	2.70052E-13	1.91980E-05	4.78507E-05
Volumetric Flow	ft^3/h	ft^3/h	ft^3/h	ft^3/h	ft^3/h
H2O	21794.2	516.577	14274.6	1.63537	2487.30
N2	73.5058	8.95611	0.174831	0.801810	50.4645
CO2	176976	1569.28	136532	0.0472183	0.191884
H2S	15.3461	0.115301	11.8795	7.86927E-06	5.70684E-05
C1	9935.99	2213.98	187.515	184.346	3534.45
C2	1417.42	311.965	46.0901	47.8756	409.625
C3	567.287	100.211	13.1592	29.7007	202.312
iC4	64.9383	9.64506	1.10738	3.68548	27.6600
nC4	184.724	28.3303	4.23738	10.8520	73.2236
iC5	46.9928	3.05167	0.190257	3.61871	28.4434
nC5	61.8825	4.68965	0.405896	4.51952	36.2170
nC6	51.0478	2.59511	0.220056	3.14338	35.5974
nC7	29.6100	0.498854	0.0211197	1.34417	25.3440
nC8	24.5251	0.388225	0.0241938	0.741875	22.3580
nC9	18.1677	0.459135	0.0818998	0.319593	16.8290
MDEA	0.370623	0.0988273	3.95918E-10	3.45310E-05	0.109112
TEG	0.00634860	0	0	0.00190990	8.09296E-05
Piperazine	0.0660665	0.0147307	8.27019E-11	0.00224564	0.0198558

Process Streams		To Thermal Oxidizer	1	2	3	4
Properties	Status:	Solved	Solved	Solved	Solved	Solved
Phase: Total	From Block:	MIX-100	From Amine Flash Tank	From Amine Still	From Glycol Flash Tank	From Glycol Still Vent
	To Block:	--	MIX-100	MIX-100	MIX-100	MIX-100
Property	Units					
Temperature	°F	129.374	181.734	124.877	135.177	167.263
Pressure	psig	1.00405	30.0041	5.00405	35	1.00405
Std Vapor Volumetric Flow	MMSCFD	4.80113	0.284150	4.34768	0.0210612	0.148242
Mass Density	lb/ft^3	0.0997472	0.180004	0.131142	0.211466	0.0489547
Molecular Weight	lb/lbmol	39.9747	27.5257	41.5026	26.7602	20.9038
Compressibility		0.995342	0.993039	0.993840	0.985149	0.996426
Specific Gravity		1.38022	0.950386	1.43297	0.923958	0.721752
Molar Flow	lbmol/h	527.153	31.1991	477.365	2.31247	16.2766
CpCv Ratio		1.28297	1.26116	1.28780	1.19507	1.24417
Dynamic Viscosity	cP	0.0160654	0.0149080	0.0162093	0.0109312	0.0127245

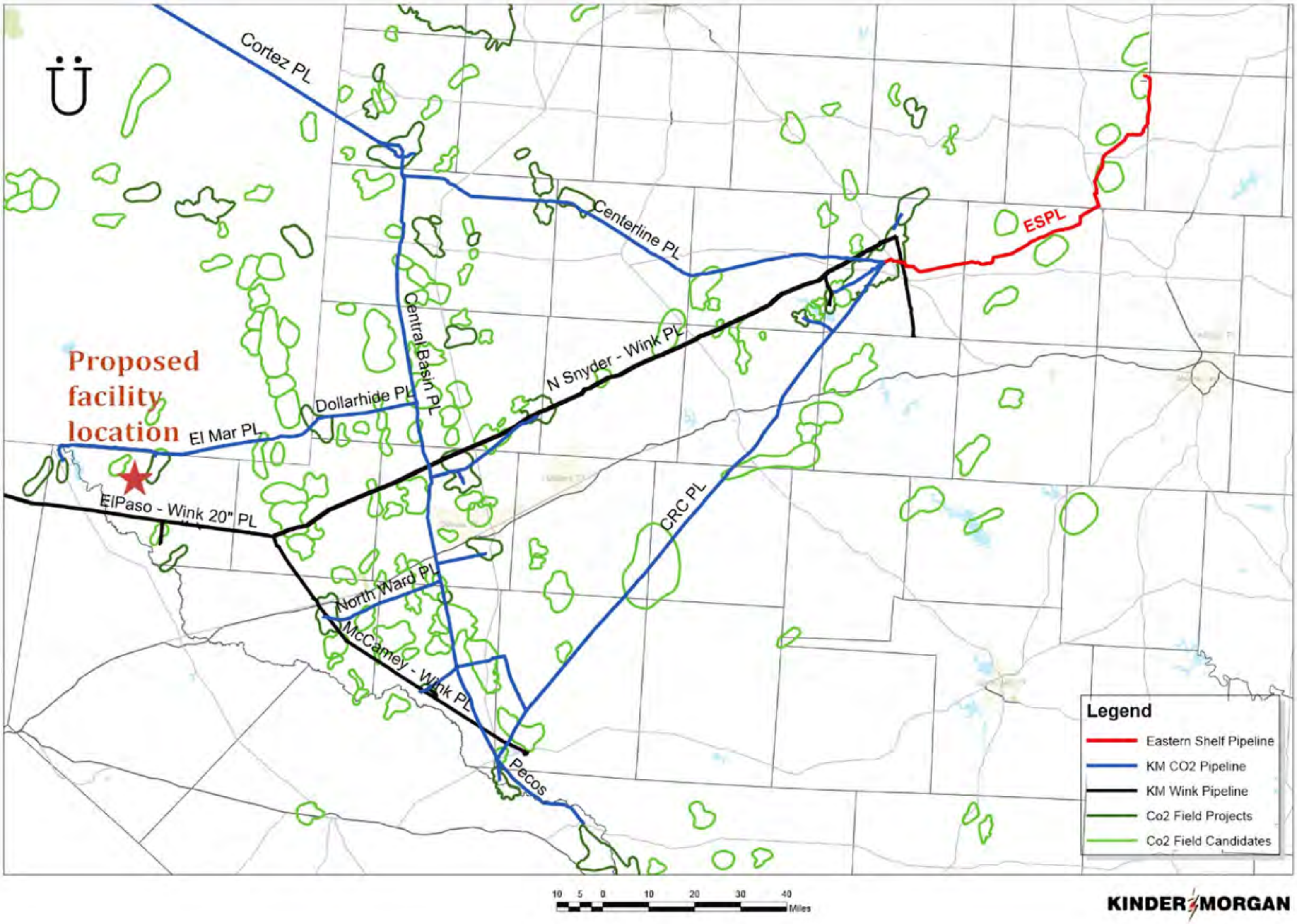
Process Streams		To Thermal Oxidizer	1	2	3	4
Composition	Status:	Solved	Solved	Solved	Solved	Solved
Phase: Vapor	From Block:	MIX-100	From Amine Flash Tank	From Amine Still	From Glycol Flash Tank	From Glycol Still Vent
	To Block:	--	MIX-100	MIX-100	MIX-100	MIX-100
Mole Fraction		%	%	%	%	%
H2O		10.3553	10.9085	9.49484	0.554138	35.9227
N2		0.0345614	0.185745	0.000114708	0.267659	0.721918
CO2		83.7502	32.9674	90.3304	0.0160488	0.00276046
H2S		0.00727027	0.00243244	0.00786953	2.69607E-06	8.22996E-07
C1		4.68150	46.1690	0.123352	62.1990	50.6693
C2		0.670837	6.57193	0.0304932	16.4604	5.89653
C3		0.269415	2.12669	0.00874517	10.3670	2.91980
iC4		0.0309403	0.206090	0.000739009	1.30335	0.400189
nC4		0.0880801	0.606430	0.00283051	3.84786	1.06057
iC5		0.0224782	0.0658097	0.000127609	1.30248	0.413070
nC5		0.0296215	0.101196	0.000272503	1.62772	0.526135
nC6		0.0245413	0.0564729	0.000148575	1.15017	0.518810
nC7		0.0142966	0.0109513	1.43399E-05	0.499618	0.370632
nC8		0.0118829	0.00858853	1.65010E-05	0.280084	0.328115
nC9		0.00884087	0.0102446	5.61792E-05	0.122871	0.247590
MDEA		0.000182361	0.00223409	2.75698E-13	1.28678E-05	0.00162203
TEG		3.14808E-06	0	0	0.000709080	1.21597E-06
Piperazine		3.20890E-05	0.000327283	5.65714E-14	0.000830195	0.000293985

Mass Flow	lb/h	lb/h	lb/h	lb/h	lb/h
H2O	983.422	61.3121	816.544	0.230853	105.335
N2	5.10380	1.62339	0.0153395	0.173390	3.29168
CO2	19429.8	452.661	18977.1	0.0163329	0.0197738
H2S	1.30617	0.0258640	1.28030	2.12480E-06	4.56533E-06
C1	395.907	231.080	9.44644	23.0744	132.306
C2	106.334	61.6530	4.37697	11.4455	28.8589
C3	62.6260	29.2578	1.84083	10.5712	20.9562
iC4	9.47989	3.73715	0.205042	1.75179	3.78591
nC4	26.9871	10.9968	0.785338	5.17175	10.0333
iC5	8.54923	1.48136	0.0439502	2.17308	4.85084
nC5	11.2661	2.27789	0.0938536	2.71573	6.17859
nC6	11.1485	1.51833	0.0611197	2.29205	7.27705
nC7	7.55172	0.342359	0.00685917	1.15769	6.04481
nC8	7.15541	0.306080	0.00899777	0.739843	6.10048
nC9	5.97732	0.409932	0.0343954	0.364418	5.16857
MDEA	0.114553	0.0830578	1.56828E-10	3.54585E-05	0.0314601
TEG	0.00249215	0	0	0.00246243	2.97220E-05
Piperazine	0.0145705	0.00879524	2.32611E-11	0.00165363	0.00412165
Molar Flow	lbmol/h	lbmol/h	lbmol/h	lbmol/h	lbmol/h
H2O	54.5882	3.40334	45.3251	0.0128143	5.84699
N2	0.182191	0.0579506	0.000547577	0.00618955	0.117504
CO2	441.492	10.2855	431.206	0.000371123	0.000449309
H2S	0.0383255	0.000758900	0.0375664	6.23459E-08	1.33956E-07
C1	24.6787	14.4043	0.588840	1.43834	8.24724
C2	3.53634	2.05038	0.145564	0.380642	0.959754
C3	1.42023	0.663508	0.0417464	0.239734	0.475244
iC4	0.163103	0.0642982	0.00352777	0.0301397	0.0651371
nC4	0.464317	0.189201	0.0135118	0.0889807	0.172624
iC5	0.118494	0.0205320	0.000609161	0.0301195	0.0672338
nC5	0.156150	0.0315721	0.00130083	0.0376407	0.0856368
nC6	0.129370	0.0176190	0.000709248	0.0265975	0.0844446
nC7	0.0753650	0.00341670	6.84535E-05	0.0115535	0.0603263
nC8	0.0626411	0.00267954	7.87699E-05	0.00647687	0.0534060
nC9	0.0466049	0.00319623	0.000268180	0.00284135	0.0402992
MDEA	0.000961323	0.000697015	1.31609E-12	2.97565E-07	0.000264011
TEG	1.65952E-05	0	0	1.63973E-05	1.97919E-07
Piperazine	0.000169158	0.000102109	2.70052E-13	1.91980E-05	4.78507E-05

Volumetric Flow	ft^3/h	ft^3/h	ft^3/h	ft^3/h	ft^3/h
H2O	21794.2	516.577	14274.6	1.63537	2487.30
N2	73.5058	8.95611	0.174831	0.801810	50.4645
CO2	176976	1569.28	136532	0.0472183	0.191884
H2S	15.3461	0.115301	11.8795	7.86927E-06	5.70684E-05
C1	9935.99	2213.98	187.515	184.346	3534.45
C2	1417.42	311.965	46.0901	47.8756	409.625
C3	567.287	100.211	13.1592	29.7007	202.312
iC4	64.9383	9.64506	1.10738	3.68548	27.6600
nC4	184.724	28.3303	4.23738	10.8520	73.2236
iC5	46.9928	3.05167	0.190257	3.61871	28.4434
nC5	61.8825	4.68965	0.405896	4.51952	36.2170
nC6	51.0478	2.59511	0.220056	3.14338	35.5974
nC7	29.6100	0.498854	0.0211197	1.34417	25.3440
nC8	24.5251	0.388225	0.0241938	0.741875	22.3580
nC9	18.1677	0.459135	0.0818998	0.319593	16.8290
MDEA	0.370623	0.0988273	3.95918E-10	3.45310E-05	0.109112
TEG	0.00634860	0	0	0.00190990	8.09296E-05
Piperazine	0.0660665	0.0147307	8.27019E-11	0.00224564	0.0198558

Process Streams		To Thermal Oxidizer	1	2	3	4
Properties	Status:	Solved	Solved	Solved	Solved	Solved
Phase: Vapor	From Block:	MIX-100	From Amine Flash Tank	From Amine Still	From Glycol Flash Tank	From Glycol Still Vent
	To Block:	---	MIX-100	MIX-100	MIX-100	MIX-100
Property	Units					
Temperature	°F	129.374	181.734	124.877	135.177	167.263
Pressure	psig	1.00405	30.0041	5.00405	35	1.00405
Std Vapor Volumetric Flow	MMSCFD	4.80113	0.284150	4.34768	0.0210612	0.148242
Mass Density	lb/ft^3	0.0997472	0.180004	0.131142	0.211466	0.0489547
Molecular Weight	lb/lbmol	39.9747	27.5257	41.5026	26.7602	20.9038
Compressibility		0.995342	0.993039	0.993840	0.985149	0.996426
Specific Gravity		1.38022	0.950386	1.43297	0.923958	0.721752
Molar Flow	lbmol/h	527.153	31.1991	477.365	2.31247	16.2766
CpCv Ratio		1.28297	1.26116	1.28780	1.19507	1.24417
Dynamic Viscosity	cP	0.0160654	0.0149080	0.0162093	0.0109312	0.0127245

Map of Nearest CO_2 Pipeline


Proposed facility location
Cortez PL
Centerline PL
Central Basin PL
Dollarhide PL
El Mar PL
N Snyder - Wink PL
ElPaso - Wink 20" PL
North Ward PL
McCamey - Wink PL
Pecos
CRC PL
ESPL
Legend
Eastern Shelf Pipeline
KM CO2 Pipeline
KM Wink Pipeline
Co2 Field Projects
Co2 Field Candidates
10 5 0 10 20 30 40 Miles
KINDER MORGAN

GHG Emission Calculations

Combustion Engines (EPNs: E-01, E-02, E-03, E-04, E-05, E-06, E-07, E-08, E-09, E-10, E-11, and E-12)

Combustion Sources of GHG Emissions

Parameter	Units	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612
EPN	-	E-01	E-02	E-03	E-04	E-05	E-06	E-07	E-08	E-09	E-10	E-11
Rated Capacity (HHV) [1]	MMBtu/hr	26.74	26.74	26.74	26.74	26.74	26.74	26.74	26.74	26.74	26.74	26.74
Hours of Operation per Year [2]	hrs/yr	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
Natural Gas Potential Throughput [3]	scf/yr	192,807,600	192,807,600	192,807,600	192,807,600	192,807,600	192,807,600	192,807,600	192,807,600	192,807,600	192,807,600	192,807,600
Fuel Gas High Heat Value (HHV) [4]	MMBtu/scf	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03

[1] Estimated Maximum Heat Input (MMBtu/hr) = Fuel Consumption (HHV) (Btu/bhp-hr) x Engine Power (bhp) x (1 MMBtu/1,000,000 Btu)
Estimated Maximum Heat Input (MMBtu/hr) = 7,533 (Btu/bhp-hr) x 3,550 (bhp) x (1 MMBtu/ 1,000,000 Btu) = 26.74 MMBtu/ hr
[2] Annual hours of operation assumed to be maximum hours per year. This includes hours for MSS emissions.
[3] Natural gas throughput is based on heat capacity of the unit, hours of operation and the fuel's high heating value
[4] High heating value per site specfic gas analysis

GHG Emission Factors for Natural Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Natural Gas.
[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for Natural Gas.

GHG Emission Factors for Natural Gas

Parameter [1]	Value	Units
Fuel Consumption (LHV)	6,791	Btu/bhp-hr
Fuel Consumption (HHV)	7,533	Btu/bhp-hr
Engine Power	3,550	bhp

[1] Per engine specification sheet.

GHG Potential Emission Calculations

EPN	Description	Fuel Type	Tier Used	Annual Emissions [1,2] (tons/yr) CO_2	CH_4	N_2O	CO_2e [4]	Hourly Emissions [3] (lb/hr) CO_2	CH_4	N_2O	CO_2e [4]
E-01	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-02	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-03	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-04	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-05	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-06	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-07	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-08	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-09	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-10	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-11	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-12	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
			Total	**164,295.52**	**3.10**	**0.31**	**164,456.66**	**37,510.39**	**0.71**	**0.07**	**37,547.18**
			Total CO_2e Emissions [4]	-	-	-	**164,456.66**	-	-	-	**37,547.18**

[1] CO_2 emissions from Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.
[2] CH_4 and N_2O emissions Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.
Annual Emissions (tons/yr) = Natural Gas Potential Throughput (scf/yr) x Natural Gas High Heat Value (MMBtu/scf) x Emission Factor (kg CO_2/MMBtu) x 2.205 (lb/kg) / 2,000 (lb/ ton)

Example CO_2 Annual Emission Rate (tons/yr) = $\frac{192{,}807{,}600 \text{ scf}}{\text{yr}} \Big| \frac{0.0012 \text{ MMBtu}}{\text{scf}} \Big| \frac{53.020 \text{ kg CO2}}{\text{MMBtu}} \Big| \frac{2.205 \text{ lb}}{\text{kg}} \Big| \frac{\text{ton}}{2{,}000 \text{ lb}} = \frac{13691.29 \text{ tons}}{\text{yr}}$

[3] Hourly Emission rates (lb/hr) = Annual Emissions (tons/yr) x 2,000 (lb/ ton) / 8,760 (hr/yr)

Example CO_2 Hourly Emission Rate (lbs/hr) = $\frac{13691.29 \text{ tons}}{\text{yr}} \Big| \frac{2{,}000 \text{ lb}}{\text{ton}} \Big| \frac{\text{yr}}{8{,}760 \text{ hr}} = \frac{3125.87 \text{ lbs}}{\text{hr}}$

kg to lb conversion 2.20 lb/kg

[4] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Annual Emission Rate (tons/yr) = CO_2 Emission Rate (tons/yr) x CO_2 GWP + CH_4 Emission Rate (tons/yr) x CH_4 GWP + N_2O Emission Rate (tons/yr) x N_2O GWP

Example CO_2e Annual Emission Rate (tons/yr) = $\frac{13691.29 \text{ tons}}{\text{yr}} \Big| 1 + \frac{0.26 \text{ tons}}{\text{yr}} \Big| 21 + \frac{0.03 \text{ tons}}{\text{yr}} \Big| 310 = \frac{13704.72 \text{ tons}}{\text{yr}}$

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

Emergency Generators (EPNs: EG-01, EG-02, EG-03, EG-04, EG-05, EG-06)

Emergency Generator GHG Emissions

Parameter	Units	Emergency Generators
EPN	-	EG-01, EG-02, EG-03, EG-04, EG-05, EG-06
Rated Capacity (HHV) [1]	MMBtu/hr	7.86
Hours of Operation per Year [2]	hrs/yr	100
#2 Fuel Oil Potential Throughput [3]	gal/yr	5,695
#2 Fuel Oil High Heat Value (HHV) [4]	MMBtu/gal	0.138

[1] Estimated Maximum Heat Input (MMBtu/hr) = Fuel Consumption (HHV) (Btu/bhp-hr) x Engine Power (bhp) x (1 MMBtu/1,000,000 Btu)

Estimated Maximum Heat Input (MMBtu/hr) = 130,984 (Btu/min) x 60 (min/hr) x (1 MMBtu/ 1,000,000 Btu) = 7.86 MMBtu/ hr

[2] Annual hours of operation assumed to be maximum hours per year. This includes hours for MSS emissions.

[3] Throughput is based on heat capacity of the unit, hours of operation and the fuel's high heating value

[4] High heating value Per 40 CFR Part 98, Subpart C, Table C-1 for Distillate Fuel Oil No. 2.

GHG Emission Factors for #2 Distillate Diesel

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	73.960	kg CO_2/MMBtu
CH_4 [2]	0.003	kg CH_4/MMBtu
N_2O [2]	0.0006	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Distillate Fuel Oil No. 2.

[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for Petroleum Fuels.

GHG Emission Factors for #2 Distillate Diesel

Parameter [1]	Value	Units
Fuel Consumption (LHV)	122,961	Btu/min
Fuel Consumption (HHV)	130,984	Btu/min
Engine Power	1,214	bhp

[1] Per engine performance data sheet.

GHG Potential Emission Calculations

EPN	Description	Fuel Type	Tier Used	Annual Emissions [1,2] (tons/yr) CO_2	CH_4	N_2O	CO_2e [4]	Hourly Emissions [3] (lb/hr) CO_2	CH_4	N_2O	CO_2e [4]
EG-01	Emergency Generator 1	#2 Fuel Oil	Tier I	64.07	2.60E-03	5.20E-04	64.29	1,281.45	0.05	0.01	1,285.76
EG-02	Emergency Generator 2	#2 Fuel Oil	Tier I	64.07	2.60E-03	5.20E-04	64.29	1,281.45	0.05	0.01	1,285.76
EG-03	Emergency Generator 3	#2 Fuel Oil	Tier I	64.07	2.60E-03	5.20E-04	64.29	1,281.45	0.05	0.01	1,285.76
EG-04	Emergency Generator 4	#2 Fuel Oil	Tier I	64.07	2.60E-03	5.20E-04	64.29	1,281.45	0.05	0.01	1,285.76
EG-05	Emergency Generator 5	#2 Fuel Oil	Tier I	64.07	2.60E-03	5.20E-04	64.29	1,281.45	0.05	0.01	1,285.76
EG-06	Emergency Generator 6	#2 Fuel Oil	Tier I	64.07	2.60E-03	5.20E-04	64.29	1,281.45	0.05	0.01	1,285.76
			Total	384.43	0.02	0.00	385.73	7,688.68	0.31	0.06	7,714.57
			Total CO_2e Emissions [4]	-	-	-	385.73	-	-	-	7,714.57

[1] CO_2 emissions from #2 Fuel Oil combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.

[2] CH_4 and N_2O emissions for #2 Fuel Oil combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.

Annual Emissions (tons/yr) = #2 Fuel Oil Potential Throughput (scf/yr) x #2 Fuel Oil High Heat Value (MMBtu/scf) x Emission Factor (kg CO_2/MMBtu) x 2.205 (lb/kg) / 2,000 (lb/ ton)

Example CO_2 Annual Emission Rate (tons/yr) = $\frac{5695\text{ gal}}{\text{yr}} \left| \frac{0.138\text{ MMBtu}}{\text{gal}} \right| \frac{73.960\text{ kg CO2}}{\text{MMBtu}} \left| \frac{2.205\text{ lb}}{\text{kg}} \right| \frac{\text{ton}}{2{,}000\text{ lb}} = \frac{64.07\text{ tons}}{\text{yr}}$

[3] Hourly Emission rates (lb/hr) = Annual Emissions (tons/yr) x 2,000 (lb/ ton) / 8,760 (hr/yr)

Example CO_2 Hourly Emission Rate (lbs/hr) = $\frac{64.07\text{ tons}}{\text{yr}} \left| \frac{2{,}000\text{ lb}}{\text{ton}} \right| \frac{\text{yr}}{100\text{ hr}} = \frac{1281.45\text{ lbs}}{\text{hr}}$

kg to lb conversion 2.20 lb/kg

[4] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Annual Emission Rate (tons/yr) = CO_2 Emission Rate (tons/yr) x CO_2 GWP + CH_4 Emission Rate (tons/yr) x CH_4 GWP + N_2O Emission Rate (tons/yr) x N_2O GWP

Example CO_2e Annual Emission Rate (tons/yr) = $\frac{64.07\text{ tons}}{\text{yr}} \left| 1 \right. + \frac{0.003\text{ tons}}{\text{yr}} \left| 21 \right. + \frac{0.0005\text{ tons}}{\text{yr}} \left| 310 \right. = \frac{64.29\text{ tons}}{\text{yr}}$

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

Amine Reboiler (EPNs: H-01, H-02, H-03, H-04, H-05, H-06)

Amine Reboiler Combustion Emissions - Greenhouse Gases

Parameter	Units	Amine Unit Reboilers
EPN	-	H-01, H-02, H-03, H-04, H-05, H-06
Rated Capacity	MMBtu/hr	40
Annual hours of Operation	hr/yr	8,760

GHG Emission Factors for Natural Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Natural Gas.
[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for Natural Gas.

GHG Potential Emission Calculations

EPN	Description	Fuel Type	Annual Emissions [1,2] (tons/yr) CO_2	CH_4	N_2O	CO_2e [4]	Hourly Emissions [3] (lb/hr) CO_2	CH_4	N_2O	CO_2e [4]
H-01	Amine Unit #1 Reboiler	Natural Gas	20,479	0.39	0.04	20,499	4,676	0.09	0.01	4,680
H-02	Amine Unit #2 Reboiler	Natural Gas	20,479	0.39	0.04	20,499	4,676	0.09	0.01	4,680
H-03	Amine Unit #3 Reboiler	Natural Gas	20,479	0.39	0.04	20,499	4,676	0.09	0.01	4,680
H-04	Amine Unit #4 Reboiler	Natural Gas	20,479	0.39	0.04	20,499	4,676	0.09	0.01	4,680
H-05	Amine Unit #5 Reboiler	Natural Gas	20,479	0.39	0.04	20,499	4,676	0.09	0.01	4,680
H-06	Amine Unit #6 Reboiler	Natural Gas	20,479	0.39	0.04	20,499	4,676	0.09	0.01	4,680
		Total	**122,873.83**	**2.32**	**0.23**	**122,994**	**28,053.39**	**0.53**	**0.05**	**28,081**
		Total CO_2e Emissions [4]	-	-	-	**122,994**	-	-	-	**28,081**

[1] CO_2 emissions from Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.
[2] CH_4 and N_2O emissions Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.

Annual Emissions (tons/yr) = Rated Capacity (MMBtu/hr) x Emission Factor (kg CO2/MMBtu) x Hours of Operation (hr/yr) x 2.205 (lb/kg) / 2,000 (lb/ ton)

Example CO2 Annual Emission Rate (tons/yr) = $\frac{40.00\ \text{MMBtu}}{\text{hr}} \cdot \frac{53.020\ \text{kg CO2}}{\text{MMBtu}} \cdot \frac{2.205\ \text{lb}}{\text{kg}} \cdot \frac{8{,}760\ \text{hr}}{\text{yr}} \cdot \frac{\text{ton}}{2{,}000\ \text{lb}} = \frac{20{,}479\ \text{tons}}{\text{yr}}$

[3] Hourly Emission rates (lb/hr) = Annual Emissions (tons/yr) x 2,000 (lb/ton) / 8,760 (hr/yr)

Example CO_2 Hourly Emission Rate (lbs/hr) = $\frac{20{,}479\ \text{tons}}{\text{yr}} \cdot \frac{2{,}000\ \text{lb}}{\text{ton}} \cdot \frac{\text{yr}}{8{,}760\ \text{hr}} = \frac{4{,}676\ \text{lb}}{\text{hr}}$

kg to lb conversion 2.20 lb/kg

[4] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Annual Emission Rate (tons/yr) = CO_2 Emission Rate (tons/yr) x CO_2 GWP + CH_4 Emission Rate (tons/yr) x CH_4 GWP + N_2O Emission Rate (tons/yr) x N_2O GWP

Example CO2e Annual Emission Rate (tons/yr) = $\frac{20{,}479\ \text{tons}}{\text{yr}} \cdot 1 + \frac{0.39\ \text{tons}}{\text{yr}} \cdot 21 + \frac{3.86\text{E-02 tons}}{\text{yr}} \cdot 310 = \frac{20{,}499\ \text{tons}}{\text{yr}}$

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

TO (EPNs: TO-1, TO-2, TO-3, TO-4, TO-5, TO-6)

TO Emissions - Greenhouse Gases - Amine Acid Gas Combustion

Parameter	Units	Thermal Oxidizer 1	Thermal Oxidizer 2	Thermal Oxidizer 3	Thermal Oxidizer 4	Thermal Oxidizer 5	Thermal Oxidizer 6
EPN	-	TO-1	TO-2	TO-3	TO-4	TO-5	TO-6
Rated Capacity [1]	MMBtu/hr	9	9	9	9	9	9
Maximum Process Vent Gas Flowrate [2]	MMscfd (wet)	4.35	4.35	4.35	4.35	4.35	4.35
Fuel Gas High Heat Value (HHV)	MMBtu/scf	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03
Annual hours of Operation	hr/yr	8,760	8,760	8,760	8,760	8,760	8,760
Thermal Oxidizer Reduction Efficiency (DRE)	%	99%	99%	99%	99%	99%	99%

[1] Scaled up from Avalon CGF #2 facility with an added safety factor of 20%.

[2] Maximum process vent gas flowrates obtained from ProMax output da 64.88888889

GHGs Emission Calculations - Process Vent Gas

EPN	Description	Fuel Type	Uncontrolled Emissions [1] (lb/hr) CO_2	CH_4	Ethane	Propane	Butanes [2]	Pentanes +
TO-1	Thermal Oxidizer 1	Natural Gas	18,977.15	9.45	4.38	1.84	0.99	0.25
TO-2	Thermal Oxidizer 2	Natural Gas	18,977.15	9.45	4.38	1.84	0.99	0.25
TO-3	Thermal Oxidizer 3	Natural Gas	18,977.15	9.45	4.38	1.84	0.99	0.25
TO-4	Thermal Oxidizer 4	Natural Gas	18,977.15	9.45	4.38	1.84	0.99	0.25
TO-5	Thermal Oxidizer 5	Natural Gas	18,977.15	9.45	4.38	1.84	0.99	0.25
TO-6	Thermal Oxidizer 6	Natural Gas	18,977.15	9.45	4.38	1.84	0.99	0.25
		Total	113,862.89	56.68	26.26	11.05	5.94	1.50

[1] Uncontrolled emission rates from ProMax output data.

[2] Piperazine has 4 carbon atoms and therefore is included in the Butane total composition.

Carbon Atoms per VOC Compound

Compound	Number of Carbon Atoms	Molecular Weight of Component (lb/lbmol)	Carbon Weight (%)
Carbon Dioxide	1	44.10	27.2%
Methane	1	16.04	74.8%
Ethane	2	30.07	79.8%
Propane	3	44.10	81.6%
Butanes	4	58.12	82.6%
Pentanes +	5	72.15	83.2%

CO_2 Conversion Emission Calculations - Process Vent Gas

EPN	Description	Converted to CO_2 [1] (lb/hr) CH_4	Ethane	Propane	Butanes	Pentanes +	Total Converted CO_2 (lb/hr)
TO-1	Thermal Oxidizer 1	9.35	8.67	5.47	3.92	1.23	28.64
TO-2	Thermal Oxidizer 2	9.35	8.67	5.47	3.92	1.23	28.64
TO-3	Thermal Oxidizer 3	9.35	8.67	5.47	3.92	1.23	28.64
TO-4	Thermal Oxidizer 4	9.35	8.67	5.47	3.92	1.23	28.64
TO-5	Thermal Oxidizer 5	9.35	8.67	5.47	3.92	1.23	28.64
TO-6	Thermal Oxidizer 6	9.35	8.67	5.47	3.92	1.23	28.64

[1] During combustion, hydrocarbons in the acid gas waste stream are oxidized to form CO_2 and water vapor.

Per 40 CFR Part 98.233(z)(2)(iii) (Subpart W), for combustion units that combust process vent gas, equation W-39A and W-39B are used to estimate the GHG emissions from additional carbon compounds in the waste gas.

Hourly Emission Rate for Compounds Converted to CO_2 (lb/hr) = Total Uncontrolled Emissions (lb/hr) x DRE (%) x # Carbons

Example CH_4 Converted to CO_2 Hourly Emission Rate (lb/hr) = $\frac{09.45\ \text{lb}}{\text{hr}}$ | 99 % | $\frac{1\ \text{Carbon Atom}}{\text{Molecule } CH_4}$ = $\frac{09.35\ \text{lb}}{\text{hr}}$

TO (EPNs: TO-1, TO-2, TO-3, TO-4, TO-5, TO-6)
GHG Emission Factors for Natural Gas - Pilot Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for
[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for

GHG Potential Emission Calculations - Pilot Gas

EPN	Description	Fuel Type	Annual Emissions [1, 2] (tons/yr) CO_2	CH_4	N_2O	CO_2e [4]	Hourly Emissions [3] (lb/hr) CO_2	CH_4	N_2O	CO_2e [4]
TO-1	Thermal Oxidizer 1	Natural Gas	4,607.77	0.09	0.01	4612.29	1,052.00	0.02	0.002	1,053.03
TO-2	Thermal Oxidizer 2	Natural Gas	4,607.77	0.09	0.01	4612.29	1,052.00	0.02	0.002	1,053.03
TO-3	Thermal Oxidizer 3	Natural Gas	4,607.77	0.09	0.01	4612.29	1,052.00	0.02	0.002	1,053.03
TO-4	Thermal Oxidizer 4	Natural Gas	4,607.77	0.09	0.01	4612.29	1,052.00	0.02	0.002	1,053.03
TO-5	Thermal Oxidizer 5	Natural Gas	4,607.77	0.09	0.01	4612.29	1,052.00	0.02	0.002	1,053.03
TO-6	Thermal Oxidizer 6	Natural Gas	4,607.77	0.09	0.01	4612.29	1,052.00	0.02	0.002	1,053.03
		Total	**27,646.61**	**0.52**	**5.21E-02**	**27,673.73**	**6,312.01**	**1.19E-01**	**1.19E-02**	**6,318.20**
		Total CO_2e Emissions [4]	**-**	**-**	**-**	**27,673.73**	**-**	**-**	**-**	**6,318.20**

[1] CO_2 emissions from Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.
[2] CH_4 and N_2O emissions Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.

Annual Emissions (tons/yr) = Rated Capacity (MMBtu/hr) x Annual Hours of Operation (hr/yr) x Emission Factor (kg CO2/MMBtu) x 2.205 (lb/kg) / 2,000 (lb/ton)

Example CO_2 Annual Emission Rate (tpy) =	9.0 MMBtu	8,760 hr	53.020 kg CO2	2.205 lb	ton	=	4,608 tons
	hr	yr	MMBtu	kg	2,000 lb		yr

[3] Hourly Emission rates (lb/hr) = Annual Emissions (tons/yr) x 2,000 (lb/ton) / 8,760 (hr/yr)

Example CO_2 Hourly Emission Rate (lbs/hr) =	4,607.77 tons	yr	2,000 lb	=	1052.00 lb
	yr	8,760 hr	ton		hr

kg to lb conversion 2.20 lb/kg

[4] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO2e Annual Emission Rate (tons/yr) = CO2 Emission Rate (tons/yr) x CO2 GWP + CH4 Emission Rate (tons/yr) x CH4 GWP + N2O Emission Rate (tons/yr) x N2O GWP

Example CO2e Annual Emission Rate (tons/yr) =	4,607.77 tons	1	+	0.09 tons	21	+	8.69E-03 tons	310	=	4,612 tons
	yr			yr			yr			yr

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

TO (EPNs: TO-1, TO-2, TO-3, TO-4, TO-5, TO-6)
GHG Potential Emission Calculations

			Hourly Emissions (lb/hr)				Annual Emissions [5,6] (tons/yr)			
EPN	Description	Fuel Type	CO_2 [1]	CH_4 [2]	N_2O [3]	CO_2e [4]	CO_2	CH_4	N_2O	CO_2e [4]
TO-1	Thermal Oxidizer 1	Natural Gas	20,058	0.11	0.05	20,076	87,853	0.50	0.22	87,932
TO-2	Thermal Oxidizer 2	Natural Gas	20,058	0.11	0.05	20,076	87,853	0.50	0.22	87,932
TO-3	Thermal Oxidizer 3	Natural Gas	20,058	0.11	0.05	20,076	87,853	0.50	0.22	87,932
TO-4	Thermal Oxidizer 4	Natural Gas	20,058	0.11	0.05	20,076	87,853	0.50	0.22	87,932
TO-5	Thermal Oxidizer 5	Natural Gas	20,058	0.11	0.05	20,076	87,853	0.50	0.22	87,932
TO-6	Thermal Oxidizer 6	Natural Gas	20,058	0.11	0.05	20,076	87,853	0.50	0.22	87,932
		Total	**120,346.75**	**0.69**	**0.30**	**120,455.10**	**527,118.77**	**3.00**	**1.33**	**527,593.33**
		Total CO_2e Emissions [4]	-	-	-	**120,455**	-	-	-	**527,593**

[1] Total CO_2 is the controlled CO_2 emissions from the oxidation of other carbon compounds in the combustion stream.

[2] CH_4 from controlled CH_4 emissions.

[3] Per 40 CFR Part 98.233(z)(2)(vi) (Subpart W), for combustion units that combust process vent gas, equation W-40 is used to estimate the N_2O emissions.

Hourly Emission Rate for N_2O (lb/hr) = Acid Gas Flowrate (MMscf/day) x (day / 24 hr) x (10^6 scf / 1 MMscf) x Subpart W Process Gas HHV (MMBtu/scf) x Emission Factor (kg/MMBtu) x (2.2046 lb/kg) + Pilot Gas N_2O Emissions (lb/hr)

Example Hourly Emission Rate for N_2O (lb/hr) = $\frac{4.35\ \text{MMscf}}{\text{day}} \left| \frac{1\ \text{day}}{24\ \text{hrs}} \right| \frac{10^6\ \text{scf}}{1\ \text{MMscf}} \left| \frac{1.235\text{E-03 MMBtu}}{\text{scf}} \right| \frac{1.00\text{E-04 kg}}{\text{MMBtu}} \left| \frac{2.2046\ \text{lb}}{\text{kg}} \right. + \frac{0.002\ \text{lb}}{\text{hr}} = \frac{0.05\ \text{lb}}{\text{hr}}$

[4] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{20{,}057.79\ \text{lb}}{\text{hr}} \left| 1 \right. + \frac{0.11\ \text{lb}}{\text{hr}} \left| 21 \right. + \frac{0.05\ \text{lb}}{\text{hr}} \left| 310 \right. = \frac{20{,}076\ \text{lb}}{\text{hr}}$

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

[5] Annual Emission Calculations (tpy) = Hourly Emission Calculations (lb/hr) x Hours of Operation per year (hrs/yr) / Conversion (lbs/ton)

Example CO2e Annual Emission Rate (tons/yr) = $\frac{20{,}075.85\ \text{lb}}{\text{hr}} \left| \frac{8{,}760\ \text{hr}}{\text{yr}} \right| \frac{\text{tons}}{2{,}000\ \text{lb}} = \frac{87{,}932\ \text{tons}}{\text{yr}}$

lb to kg conversion 2.20 lb/kg

TEG Dehydrator Reboiler (EPNs: RB-01, RB-02, RB-03, RB-04, RB-05, RB-06)

TEG Dehydrator Reboiler Combustion Emissions - Greenhouse Gases

Parameter	Units	Glycol Dehydrator Reboilers
EPN	-	RB-01, RB-02, RB-03, RB-04, RB-05, RB-06
Rated Capacity	MMBtu/hr	1.5
Annual hours of Operation	hr/yr	8,760

GHG Emission Factors for Natural Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table

[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-

GHG Potential Emission Calculations

EPN	Description	Fuel Type	Annual Emissions [1,2] (tons/yr) CO_2	CH_4	N_2O	CO_2e [4]	Hourly Emissions [3] (lb/hr) CO_2	CH_4	N_2O	CO_2e [4]
RB-01	Glycol Dehydrator #1 Reboiler	Natural Gas	768	1.45E-02	1.45E-03	769	175	3.31E-03	3.31E-04	176
RB-02	Glycol Dehydrator #2 Reboiler	Natural Gas	768	1.45E-02	1.45E-03	769	175	3.31E-03	3.31E-04	176
RB-03	Glycol Dehydrator #3 Reboiler	Natural Gas	768	1.45E-02	1.45E-03	769	175	3.31E-03	3.31E-04	176
RB-04	Glycol Dehydrator #4 Reboiler	Natural Gas	768	1.45E-02	1.45E-03	769	175	3.31E-03	3.31E-04	176
RB-05	Glycol Dehydrator #5 Reboiler	Natural Gas	768	1.45E-02	1.45E-03	769	175	3.31E-03	3.31E-04	176
RB-06	Glycol Dehydrator #6 Reboiler	Natural Gas	768	1.45E-02	1.45E-03	769	175	3.31E-03	3.31E-04	176
		Total	**4,607.77**	**0.09**	**8.69E-03**	**4,612**	**1,052.00**	**1.98E-02**	**1.98E-03**	**1,053**
		Total CO_2e Emissions [4]	-	-	-	**4,612**	-	-	-	**1,053**

[1] CO_2 emissions from Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.

[2] CH_4 and N_2O emissions Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.

Annual Emissions (tons/yr) = Rated Capacity (MMBtu/hr) x Emission Factor (kg CO2/MMBtu) x Hours of Operation (hr/yr) / 1,000 (lb/ton)

Example CO2 Annual Emission Rate (tons/yr) = $\frac{1.50\ \text{MMBtu}}{\text{hr}} \cdot \frac{53.020\ \text{kg CO2}}{\text{MMBtu}} \cdot \frac{8{,}760\ \text{hr}}{\text{yr}} \cdot \frac{2.205\ \text{lb}}{\text{kg}} \cdot \frac{\text{ton}}{2{,}000\ \text{lb}} = \frac{768\ \text{tons}}{\text{yr}}$

[3] Hourly Emission rates (lb/hr) = Annual Emissions (tons/yr) x 1.000 (lb/ton) x 2.20 (lb/kg) / 8.760 (hr/yr)

Example CO_2 Hourly Emission Rate (lbs/hr) = $\frac{768\ \text{tons}}{\text{yr}} \cdot \frac{2{,}000\ \text{lb}}{\text{ton}} \cdot \frac{\text{yr}}{8{,}760\ \text{hr}} = \frac{175\ \text{lb}}{\text{hr}}$

kg to lb conversion 2.20 lb/kg

[4] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO2e Annual Emission Rate (tons/yr) = CO2 Emission Rate (tons/yr) x CO2 GWP + CH4 Emission Rate (tons/yr) x CH4 GWP + N2O Emission Rate (tons/yr) x N2O GWP

Example CO2e Annual Emission Rate (tons/yr) = $\frac{768\ \text{tons}}{\text{yr}} \cdot 1 + \frac{1.45\text{E-}02\ \text{tons}}{\text{yr}} \cdot 21 + \frac{1.45\text{E-}03\ \text{tons}}{\text{yr}} \cdot 310 = \frac{769\ \text{tons}}{\text{yr}}$

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

GHG EMISSION CALCULATIONS FOR TANKS

Tanks (EPNs:PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, PWTK-06)

Parameter[1]	Units	Water Tanks 1-6
EPN	-	PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, PWTK-06
FIN	-	PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, PWTK-06
Maximum Process Vent Gas Flowrate	MMscfd	3.98E-02
Annual hours of Operation	hr/yr	8,760

[1] Scaled up from Anadarko Avalon CGF #2 facility.

[2] Obtained from E&P Tanks output for storage tanks.

EPN	FIN	Description	Uncontrolled Emissions[1] (lb/hr)			Uncontrolled Emissions[1] (tpy)		
			CO_2	CH_4	CO_2e	CO_2	CH_4	CO_2e
PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, PWTK-06	PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, PWTK-06	Produced Water Tanks 1-6	0.000	0.003	0.063	0.001	0.014	0.295
		Total	0.00E+00	3.00E-03	0.06	1.00E-03	0.01	0.30

[1] Produced Water Tanks emissions assumed 1% Condensate. Uncontrolled emissions for Condensate Tanks were determined using E&P Tanks. Condensate tanks are pressurized, and consequently do not actually emit GHGs.

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

Flares (EPNs: FL-01, FL-02, FL-03)

Parameter [1]	Units	Flares
EPN	-	FL-01, FL-02, FL-03
FIN	-	FL-01, FL-02, FL-03
Pilot Gas Fuel Flowrate per flare	scf/hr	250
Pilot Gas Fuel flowrate	scf/yr	2,190,000
High Heat Value (HHV) [2]	MMBtu/scf	1.22E-03
Annual hours of Operation	hr/yr	8,760
Flare Reduction Efficiency (DRE) [3]	%	98.0

[1] Scaled up from Anadarko Avalon CGF #2 facility.
[2] Obtained from E&P Tanks output for storage tanks.
[3] Flare Reduction Efficiency (generic) is 98% per TCEQ Flares Guidance.

GHG Emission Factors for Natural Gas - Pilot Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Natural Gas.
[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for Natural Gas.

GHG Potential Emission Calculations - Pilot Gas

EPN	FIN	Description	Fuel Type	Annual Emissions [1,2] (tons/yr) CO_2	CH_4	N_2O	CO_2e [4]	Hourly Emissions [3] (l CO_2	CH_4
FL-01	FL-01	Flare #1	Natural Gas	155.51	0.003	0.0003	155.66	35.51	0.00
FL-02	FL-02	Flare #2	Natural Gas	155.51	0.003	0.0003	155.66	35.51	0.00
FL-03	FL-03	Flare #3	Natural Gas	155.51	0.003	0.0003	155.66	35.51	0.00
			Total	466.54	0.01	8.80E-04	466.99	106.52	2.01E-03

[1] CO_2 emissions from Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.
[2] CH_4 and N_2O emissions Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.

Annual Emissions (tons/yr) = Rated Capacity (MMBtu/hr) x Annual Hours of Operation (hr/yr) x Emission Factor (kg CO2/MMBtu) x 2.205 (lb/kg) / 2000 (lb/ton)

Example CO_2 Annual Emission Rate (tpy) =	2,190,000 scf / yr	1.22E-03 MMBtu / scf	53.020 kg CO2 / MMBtu	2.205 lb / kg	ton / 2,000 lb	=	156 tons / yr

[3] Hourly Emission rates (lb/hr) = Annual Emissions (tons/yr) x 2,000 (lb/ton) / 8,760 (hr/yr)

Example CO_2 Hourly Emission Rate (lbs/hr) =	155.51 tons / yr	yr / 8,760 hr	2,000 lb / ton	=	155.66 lb / hr

kg to lb conversion 2.20 lb/kg

[4] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO2e Annual Emission Rate (tons/yr) = CO2 Emission Rate (tons/yr) x CO2 GWP + CH4 Emission Rate (tons/yr) x CH4 GWP + N2O Emission Rate (tons/yr) x N2O GWP

Example CO2e Annual Emission Rate (tons/yr) =	155.51 tons / yr	1	+	2.93E-03 tons / yr	21	+	2.93E-04 tons / yr

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

GHG EMISSION CALCULATIONS FOR TRUCK LOADING

Truck Loading Emission Factors

S = Saturation Factor [1]	P = True Vapor Pressure of Liquid Loaded (psia) [2]	M = Molecular Weight of Vapors (lb/lb-mole) [2]	T = Temperature of Bulk Liquid Loaded (°R) [2]	Hourly Loading Rate (gal/hr) [3]	Annual Loading Rate (gal/yr) [4]	Loading Loss (lb/1000 gal) [5]
0.6	3.4147	69	564.67	5,460	3,066,000	3.12

[1] The S-factor is based on submerged loading, dedicated normal.
[2] Worst case temperature assumed to be maximum ambient temperature for Loving, TX
[3] Hourly Loading Rate based on maximum capacity of loading truck in 1 hour.
[4] Annual Loading Rate based on proposed site-wide throughput of 200 bbl/day for each liquid.
[5] Based on Equation $L_L = 12.46 * SPM/T$ from AP-42, Chapter 5, Section 5.2-4.

Proposed Hourly and Annual Emissions for Truck Loading

EPN	Source Name	Hourly Emissions (lb/hr) [1]	Annual Emissions (tons/yr) [2]
TL-2	Produced Water Truck Loading [3]	0.17	0.048
	Total CH_4 [4]	**0.17**	**0.05**
	Total CO_2e [5]	**3.58**	**1.00**

[1] Hourly Emissions (lb/hr) = Loading Losses (lb/1000 gal) x Hourly Loading Rate (gal/hr)

EPN TL-2 Hourly Emissions (lb/hr) = $\frac{3.12\ \text{lb}}{1000\ \text{gal}} \times \frac{5460\ \text{gal}}{\text{hr}} \times 0.01 = 0.17$ lb/hr

[2] Annual Emissions (tpy) = Loading Losses (lb/1000 gal) x Annual Loading Rate (gal/yr) / 2000 (lb/ton)

EPN TL-2 Annual Emissions (tpy) = $\frac{0.17\ \text{lb}}{1000\ \text{gal}} \times \frac{3{,}066{,}000\ \text{gal}}{\text{yr}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} = \frac{0.05\ \text{tons}}{\text{yr}}$

[3] Assumed 1% of throughput is condensate. Multiply results by 0.01.
[4] Assumed all VOC is CH_4 for conservatism.
[5] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Hourly Emission Rate (lb/hr) = CH_4 Emission Rate (lb/hr) x CH_4 GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{0.17\ \text{lb}}{\text{hr}} \times 21 = 3.6$ lb/hr

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

kg to lb conversion 2.204623 lb/kg

GHG EMISSION CALCULATIONS FOR PROPOSED FUGITIVES

Site-wide Fugitive Components (EPN: FUG)

Fugitive Counts and VOC Content

Stream	Valves	Flanges	Relief Valves	Open-ended Lines	Connectors	Other	CO_2 Content (Weight %) [1]	CH_4 Content (Weight %) [1]
Fuel Gas/Residue Gas	2780	2780	300	300	8340	200	21.81%	49.58%
Light Oil	950	950	30	100	2850	100	0.08%	0.11%

[1] Data obtained from representative gas analysis.

LDAR Control (%)

Stream	Valves	Flanges	Relief Valves	Open-ended Lines	Connectors	Other
Fuel Gas/Residue Gas	97%	30%	97%	97%	30%	0%
Light Oil	97%	30%	0%	97%	30%	0%

[1] Control efficiency for each type of component for 28 MID Leak Detection and Repair Program (LDAR)

Oil and Gas Production Operations Emission Factors

Stream	Emission Factor [1] (lb/hr)/component					
	Valves	Flanges	Relief Valves	Open Ended Lines	Connectors	Other
Gas	0.00992	0.00086	0.0194	0.00441	0.00044	0.0194
Light Oil	0.0055	0.000243	0.0165	0.00309	0.000463	0.0165

[1] Oil and Gas Production emission factors obtained from TCEQ, Industrial Emissions Assessment Section, Components: RG-360, January 2008. For conservatism it was assumed that components in CO_2 Service have the same emission factors as gas components.

Hourly GHG Emissions

Component	Stream	Hourly Emissions (lb/hr) [1]						
		Valves	Flanges	Relief Valves	Open Ended Lines	Connectors	Other	Total
CO_2	Gas	0.18	0.37	0.04	0.01	0.56	0.85	2.00
	Light Oil	0.03	0.04	0.11	0.00	0.20	0.36	0.74
CH_4	Gas	0.41	0.83	0.09	0.02	1.27	1.92	4.54
	Light Oil	0.00	0.00	0.00	0.0000	0.00	0.00	0.00
							Total CO_2	2.74
							Total CH_4	4.55
							Total CO_2e [2]	98.23

[1] Hourly Controlled CH_4 Emission Rate (lb/hr) = Oil and Gas Factor x Component Count x (%CH_4 content in LNG / 100)

Hourly Emission Rate for Valves from Gas Service (lb/hr) = 9.92E-03 lb / hr-component | 2780 | 49.58% / 100 | [1 - 0.97%] = 0.18 lb/hr

[2] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Hourly Emission Rate (lb/hr) = CH_4 Emission Rate (lb/hr) x CH_4 GWP + CO_2 Emission Rate (lb/hr) x CO_2 GWP

Example CO_2e Hourly Emission Rate (lb/hr) = 2.74 lb / hr | 21 + 4.55 lb / hr | 1 = 98.2 lb / hr

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

Annual GHG Emissions

Component	Stream	Annual Emissions (tons/yr) [1]						
		Valves	Flanges	Relief Valves	Open Ended Lines	Connectors	Other	Total
CO_2	Gas	0.79	1.60	0.17	0.04	2.45	3.71	8.75
	Light Oil	0.15	0.15	0.47	0.01	0.88	1.58	3.24
CH_4	Gas	1.80	3.63	0.38	0.09	5.58	8.43	19.90
	Light Oil	0.00	0.00	0.00	0.00	0.00	0.01	0.02
							Total CO_2	12.00
							Total CH_4	19.92
							Total CO_2e [2]	430.24

[1] Annual Emissions (tons/yr) = Hourly Emissions (lb/hr) x 8,760 (hrs/yr) / 2204.623 (lb/tons)

Annual Emissions for Valves in Gas Service (tons/yr) = 0.18 lb / hr | 8,760 hrs / yr | ton / 2,000 lb = 0.79 tons/yr

[2] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Hourly Emission Rate (lb/hr) = CH_4 Emission Rate (lb/hr) x CH_4 GWP + CO_2 Emission Rate (lb/hr) x CO_2 GWP

Example CO2e Emission Rate (tons/yr) = 12.00 tons / yr | 1 + 19.92 tons / yr | 21 = 430.2 tons / yr

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials

CO_2	1
CH_4	21
N_2O	310

lb to ton conversion 2,000.00 lb/ton

Site-wide Maintenance, Startup, and Shutdown (MSS) Emissions (EPN: MSS)

Compressor Blowdown VOC Emissions

Parameter [1]	Units	MSS - Compressor Blowdowns [2]	MSS - Vessel Blowdown	MSS- Pigging Operations [3]
EPN		MSS-compressors	MSS-vessel	MSS-pigging
FIN		FL-01, FL-02, FL-03	FL-01, FL-02, FL-03	MSS-pigging
Volume	scf	660,303	26,400	--
Mass	lb/yr	--	--	3244.63
Annual Hours of Operation	hrs/yr	1872	16.5	6
% CO_2	Wt %	4.56%	4.56%	0.08%
% CH_4	Wt %	59.98%	59.98%	0.11%
CO_2 Molecular Weight	lb/lb-mol	44.01	44.01	44.01
CH_4 Molecular Weight	lb/lb-mol	16.04	16.04	16.04
Flare Destruction Efficiency (DRE) [4]	%	98.0	98.0	0.0

[1] Scaled up from Anadarko Avalon CGF #2 facility.
[2] Assumed 12 compressor blowdown per month per engine for the compressor engines
[3] Scaled up from Anadarko Avalon #2 Facility, which assumed pounds per year based on engineering knowledge
[4] EPNs MSS-compressors and MSS-vessel routed to flare

GHGs Emission Calculations - Process Vent Gas

EPN	FIN	Description	Uncontrolled Emissions (lb/hr) CO_2	CH_4
MSS-compressors [1]	FL-01, FL-02, FL-03	MSS - Compressor Blowdowns	1.87	8.94
MSS-Vessel [1]	FL-01, FL-02, FL-03	MSS - Vessel Blowdown	8.46	40.57
MSS-Pigging [2]		MSS- Pigging Operations	0.43	0.59
		Total	**10.76**	**50.11**

[1] Hourly Emissions (lb/hr) = Volume (scf/yr) * (lb-mol/379.4 scf) *Molecular Weight (lb/lb-mol) * Compound Wt % / Hours per year (hr/yr)

$$\text{Hourly Emissions for } CO_2 \text{ (lb/hr)} = \frac{660{,}303 \text{ scf}}{1 \text{ yr}} \Big| \frac{\text{lb-mol}}{379.4 \text{ scf}} \Big| \frac{44.01 \text{ lb}}{\text{lb-mol}} \Big| \frac{4.56\%}{1872 \text{ hr/yr}} = 1.87 \text{ lb/hr}$$

[2] Hourly Emissions (lb/hr) = Pounds per Year (lb/yr) / Hours per Year (hr/yr) x Compound Wt%

$$\text{Hourly Emissions for } CO_2 \text{ (lb/hr)} = \frac{3244.63 \text{ lb}}{\text{yr}} \Big| \frac{\text{yr}}{6 \text{ hr}} \Big| 0.08\% = 0.43 \text{ lb/hr}$$

Carbon Atoms per VOC Compound

Compound	Number of Carbon Atoms	Molecular Weight of Component (lb/lbmol)	Carbon Weight (%)
Carbon Dioxide	1	44.10	27.2%
Methane	1	16.04	74.8%
Ethane	2	30.07	79.8%
Propane	3	44.10	81.6%
Butanes	4	58.12	82.6%
Pentanes +	5	72.15	83.2%

CO_2 Conversion Emission Calculations - Process Vent Gas

EPN	FIN	Description	Converted to CO_2 [1] (lb/hr) CH_4
MSS-compressors	FL-01, FL-02, FL-03	MSS - Compressor Blowdowns	8.77
MSS-vessel	FL-01, FL-02, FL-03	MSS - Vessel Blowdown	39.76
MSS-pigging	MSS-pigging	MSS- Pigging Operations	0
		Total	**48.53**

[1] During combustion, hydrocarbons in the acid gas waste stream are oxidized to form CO_2 and water vapor.

Per 40 CFR Part 98.233(z)(2)(iii) (Subpart W), for combustion units that combust process vent gas, equation W-39A and W-39B are used to estimate the GHG emissions from additional carbon compounds in the waste gas.

Hourly Emission Rate for Compounds Converted to CO_2 (lb/hr) = Total Uncontrolled Emissions (lb/hr) x DRE (%) x # Carbons

Example CH_4 Converted to CO_2 Hourly Emission Rate (lb/hr) = $\frac{8.94 \text{ lb}}{\text{hr}} \;\Big|\; 98\,\% \;\Big|\; \frac{1 \text{ Carbon Atom}}{\text{Molecule } CH_4}$ = $\frac{8.77 \text{ lb}}{\text{hr}}$

GHG Potential Emission Calculations

EPN	FIN	Description	Hourly Emissions (lb/hr) CO_2	Hourly Emissions (lb/hr) CH_4	Annual Emissions [1] (tons/yr) CO_2	Annual Emissions [1] (tons/yr) CH_4
MSS-compressors	FL-01, FL-02, FL-03	MSS - Compressor Blowdowns	11	0.18	10	0.167
MSS-vessel	FL-01, FL-02, FL-03	MSS - Vessel Blowdown	48	0.81	0	0.007
MSS-pigging	MSS-pigging	MSS- Pigging	4.33E-01	1.19E-02	1.30E-03	3.57E-05
		Total	**59.29**	**1.00**	**10.35**	**0.17**
		Total CO_2e Emissions [2]	-	**80.34**	-	**14.01**

[1] Annual Emissions (tons/yr) = Hourly Emissions (lb/hr) *Hours per Year (hr/yr) / 2000 (lb/ton)

Annual Emissions (tons/yr) = $11 \;\Big|\; \frac{1872 \text{ hr}}{\text{yr}} \;\Big|\; \frac{\text{ton}}{2{,}000 \text{ lb}}$ = $\frac{9.95 \text{ tons}}{\text{yr}}$

[2] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Hourly Emission Rate (lb/hr) = CH_4 Emission Rate (lb/hr) x CH_4 GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{59.29 \text{ lb}}{\text{hr}} \;\Big|\; 1$ + $\frac{1.00 \text{ lb}}{\text{hr}} \;\Big|\; 21$ = 80.34 lb/hr

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials:

CO_2	1
CH_4	21
N_2O	310

Conversion: lb to kg 2.204623 lb/kg

BACT Cost Analysis

Cost Estimation for Transfer of CO_2 via Pipeline - Amine Vent

CO_2 Pipeline and Emissions Data

Parameter	Value	Units
Minimum Length of Pipeline	12	miles
Average Diameter of Pipeline	6	inches
CO_2 emissions from vents	527,118.77	tons/year
CO2 capture efficiency	90%	
Captured CO_2	474,406.89	tons/year

CO_2 Transfer Cost Estimation[1]

Cost Type	Units	Cost Equation	Cost ($)
		Pipeline Costs	
Materials/Labor	$	$7,605,000.00	$7,605,000.00
Right of Way	$ Diameter (inches), Length (miles)	$48,037 + $1.20 x L x (577 x D + 29,788)	$527,000.00
		Other Capital	
Gas Treatment Equipment and Labor	$	$35,933,000.00	$35,933,000.00
		Operation & Maintenance (O&M)	
Fixed O&M per Year	$	$1,826,000.00	$1,826,000.00
		Total CCS Cost	$45,891,000.00

Amortized CCS Cost

Equipment Life (years)[2]	10
Interest rate	0.07
Capital Recovery Factor (CRF)[3]	0.142
Total Capital Investment (TCI)	$44,065,000.00
Amortized Installation Cost (TCI*CRF)	$6,257,230.00
Total CCS Annualized Cost	**$8,083,230.00**
Total Annualized cost/ton CO_2	**$17.04**

Amortized Project Cost (without CCS)

Equipment Life[2]	10
Interest rate	0.07
Capital Recovery Factor (CRF)[3]	0.142
Total Capital Investment (TCI)	$117,000,000.00
Amortized Installation Cost (TCI*CRF)	$16,614,000.00
Annual Operating Cost Estimation	$8,000,000.00
Total Project Annualized Cost	**$24,614,000.00**

[1] Cost estimation guidelines obtained from "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs", DOE/NETL-2010/1447, dated March 2011 and DBJVG CO2 Sales Definition Study Aug. 16, 2012.

[2] Pipeline and Equipment life is estimated at 10 years due to the life cycle of the reservoir.

[3] Capital Recovery Fraction = Interest Rate x (1+ Interest Rate) ^ Pipeline Life) / [(1 + Interest Rate) ^ Pipeline Life - 1]

[4] This cost estimation does not include capital and O&M costs associated with the compression equipment or processing equipment