GREENHOUSE GAS PREVENTION OF SIGNIFICANT DETERIORATION AIR PERMIT APPLICATION

Lone Star NGL

Lone Star NGL Fractionators LLC
Mont Belvieu Gas Plant
FRAC III Project
Mont Belvieu, Chambers County, Texas

Project Number: 84800475-08.001

June 2013

TITAN ENGINEERING, INC.

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1 INTRODUCTION

Lone Star NGL Fractionators LLC (Lone Star) is applying to the Environmental Protection Agency (EPA) and to the Texas Commission on Environmental Quality (TCEQ) for authorization to construct a natural gas liquids (NGL) processing plant (FRAC III Plant) and associated equipment (the Project) at the Mont Belvieu Gas Plant (Site), which is located in Chambers County, Texas. Chambers County is designated as severe nonattainment for ozone, with oxides of nitrogen (NO_X) and volatile organic compounds (VOC) being regulated as precursors to ozone. Chambers County is designated as attainment/unclassifiable for all other criteria air pollutants.

The FRAC III Plant will be comprised of the following air emission sources:

- an amine unit, controlled by thermal oxidizer,
- a thermal oxidizer, which controls amine unit emissions,
- a molecular sieve dehydration unit,
- two gas-fired heaters, which vent to a common Selective Catalytic Reduction (SCR) control device,
- atmospheric storage tanks and associated loading/unloading,
- fugitives from associated piping/equipment leaks, controlled by Leak Detection and Repair (LDAR) program, with certain vents controlled by flare,
- two diesel-fired emergency generators and a diesel-fired firewater pump,
- maintenance/startup/shutdown (MSS) activities, with certain vents controlled by flare, and
- a flare that controls certain MSS emissions and fugitive equipment component leaks.

The Site currently includes two NGL processing plants (i.e., FRAC I Plant and FRAC II Plant, which include an Export FRAC). FRAC I Plant and FRAC II Plant each have the following equipment: an amine unit, controlled by a thermal oxidizer, a molecular sieve dehydration unit, two gas-fired heaters, an amine storage tank, a slop water tank and associated loading, fugitives, and MSS activities. FRAC I Plant also has a second amine tank, a diesel tank, two emergency diesel generators, and an emergency diesel firewater pump. The Export FRAC has fugitives and MSS activities.

The Site currently has both EPA and TCEQ air permit authorizations. The EPA authorization is limited to Greenhouse Gases (GHG). FRAC I Plant was originally authorized by TCEQ prior to implementation of the Tailoring Rule (which became effective January 2, 2011). Therefore, GHG permitting requirements did not apply. The FRAC II Plant was permitted after the implementation of the Tailoring Rule, and triggered Prevention of Significant Deterioration (PSD) review for GHG. The FRAC I Plant was modified during the construction phase, so portions of that plant were included in the FRAC II GHG PSD permit application. On October 12, 2012, EPA issued GHG PSD Permit No. PSD-TX-93813-GHG authorizing FRAC I Plant modifications and FRAC II Plant construction. On May 29, 2012, the TCEQ revised Standard Permit Registration No. 93813 authorizing the non-GHG emissions associated with the FRAC I Plant modifications and the FRAC II Plant construction.

The three NGL processing plants (FRAC I Plant, FRAC II Plant, and FRAC III Plant) are operationally independent from each other. Therefore, this GHG PSD air permit application addresses FRAC III Plant emissions only (i.e., Lone Star requests a stand-alone permit for the FRAC III Plant).

Like the FRAC I Plant and the FRAC II Plant, the proposed FRAC III Plant will be located near Lone Star's (formerly LDH Energy's) existing North Terminal transfer and storage facility in Mont Belvieu. The gas plant, however, is independent of the existing North Terminal. The primary Standard Industrial Classification (SIC) code for the gas plant (1321, Natural Gas Liquids) is different than that of the North Terminal (4613, Petroleum Pipelines, Refined). Because of the independence of the two plants, LDH Energy requested, and received, a new Regulated Entity Number (RN) from the TCEQ: RN106018260. Lone Star will retain this RN for the FRAC III Plant.

1.1 Purpose and Overview of Application

The Project will result in emissions of GHG, carbon monoxide (CO), oxides of nitrogen (NO_X), particulate matter (PM, PM_{10}, and $PM_{2.5}$), sulfur dioxide (SO_2), and volatile organic compounds (VOC). The GHG are calculated as carbon dioxide equivalents (CO_2e). As discussed in more detail in Section 1.2, Lone Star is requesting both EPA's and TCEQ's authorization for the construction of the Project, because Texas is now under dual permitting authority.

Under EPA's authority, the Project will constitute a major modification to an existing major source of GHG, because the net change in GHG emissions will be greater than the major modification threshold of 75,000 tons per year (T/yr) CO_2e. Therefore, the Project triggers PSD review for GHG. **This document constitutes Lone Star's application to EPA for a PSD Permit for GHG emissions from the FRAC III Plant.**

Under TCEQ's authority, the Project has been evaluated for PSD and nonattainment new source review (NNSR) applicability for criteria air pollutants other than GHG. Under the NNSR regulations, the Project will constitute a major modification to an existing major source for NO_X and VOC, because the Project-related change in NO_X and VOC emissions will be greater than the netting threshold of 5 T/yr each and, when considered together with contemporaneous changes, will be greater than the major modification threshold of 25 T/yr each. Under PSD regulations, the Project will not constitute a new major source or a major modification, because the Project-related increases in CO, NO_X, PM, PM_{10}, $PM_{2.5}$, and SO_2 emissions will be less than their respective PSD significance thresholds. Therefore, on May 17, 2013, Lone Star submitted an application to TCEQ for an NNSR Permit for NO_X and VOC and for a minor source permit for CO, PM, PM_{10}, $PM_{2.5}$, and SO_2 (TCEQ Air Permit No. 110274 and TCEQ Air Permitting Project No. 193441).

This document has been prepared based upon information provided by Lone Star and written and verbal EPA and TCEQ guidance. The remainder of this document is structured as follows:

- Section 2 presents a description of the proposed Site, including area maps, plot plans, a process description, and process flow diagram;
- Section 3 presents a discussion of the proposed Project GHG emissions, the methodologies used to estimate the GHG emissions, and the monitoring methods that Lone Star proposes to implement for demonstrating compliance with the proposed GHG emission rates;
- Section 4 presents a detailed five-step Best Available Control Technology (BACT) evaluation for the proposed Project GHG emission sources;
- Section 5 identifies the state and federal regulations that apply to the Project;
- Section 6 describes the Air Quality Analysis (AQA) requirements for the Project; and
- Section 7 presents a list of references used in the preparation of this GHG PSD air permit application document.

This document also contains the following appendices:

- Appendix A contains the applicable TCEQ permit application forms and tables;
- Appendix B presents detailed GHG emission rate calculations;
- Appendix C contains vendor specifications for the Project equipment;
- Appendix D contains the documentation in support of the Section 4 BACT analysis; and
- Appendix E contains documentation in support of the remainder of the air permit application.

1.2 PSD Applicability

Beginning on January 2, 2011, GHG are a regulated criteria pollutant under the PSD major source permitting program codified in Title 40 Code of Federal Regulations (CFR) Part 52 when they are emitted by new sources or modifications in amounts that meet the Tailoring Rule's set of applicability thresholds, which phase in over time. For PSD purposes, GHGs are a single air pollutant defined as the aggregate group of the following gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), and hydrofluorocarbons (HFCs).

For GHGs, the Tailoring Rule does not change the basic PSD applicability process for evaluating whether there is a new major source or modification. The applicability threshold for the source is based on CO_2e emissions as well as its GHG mass emissions

Because the Site is located in an area designated as severe nonattainment for ozone, the Project's NO_X and VOC emissions are evaluated for potential applicability of NNSR permitting requirements. The Site is in an area designated as attainment/unclassifiable for all remaining criteria air pollutants; therefore the Project is reviewed for potential applicability of PSD permitting requirements for GHG as well as CO, NO_X, PM, PM_{10}, $PM_{2.5}$, and SO_2.

In December 2010, EPA finalized a rule that designates EPA as the permitting authority for GHG emitting sources in Texas by declaring a partial disapproval of the Texas State Implementation Plan (SIP). This rule is in effect until the EPA approves a SIP that allows Texas to regulate GHG. At this time, EPA is the designated permitting authority for all GHG PSD permits in Texas. EPA stated in its white paper titled "Issuing Permits for Sources with Dual PSD Permitting Authorities," dated April 19, 2011, "[i]n the case of a source or project that has both GHGs and non-GHGs that are subject to PSD . . . the State will issue the non-GHG portion of the permit and EPA will issue the GHG portion." See *http://www.epa.gov/nsr/ghgqa.htm*.

Prior to the Project, the Site is an existing major source of NO_X and VOC with respect to NNSR permitting, because the Site has a PTE greater than 25 T/yr. The Site is an existing major source with respect to PSD permitting under EPA authority, because the Site has a PTE greater than 100,000 T/yr CO_2e and greater than 250 T/yr GHG (Mass basis). The Site is not a major source with respect to PSD permitting under TCEQ authority, because the only pollutant that makes the Site major is GHG. The following paragraphs describe the NNSR/PSD applicability under EPA and TCEQ permitting authority.

1.2.1 NNSR Applicability (TCEQ Authority)

As stated previously, the Site is an existing major source of NO_X and VOC. The Project-related increases, including fugitive emissions, are greater than the NNSR netting threshold of 5 T/yr. Because the entire Site has been constructed within the past five (5) years, Lone Star is electing to forego netting and claim the Project triggers NNSR for both NO_X and VOC.

1.2.2 PSD Applicability (TCEQ Authority)

As stated previously, the Site is not an existing major source with respect to criteria air pollutants other than GHG. Therefore, in order to trigger PSD review under TCEQ permitting authority, the Project would have to constitute a new major source. The Project does not constitute a new major source of any non-GHG criteria air pollutant. Moreover, after the Project, the Site in its entirety will not constitute a major source of any non-GHG criteria air pollutant. Therefore, the Project does not trigger PSD permitting for any non-GHG criteria air pollutant.

1.2.3 PSD Applicability (EPA Authority)

As stated previously, the Site is an existing major source of GHG. Therefore, any criteria pollutant (i.e., GHG, CO, NO_X, PM, PM_{10}, $PM_{2.5}$, and SO_2) can trigger PSD review under EPA authority if the Project constitutes a major modification. In addition, if the Project triggers a new major source of GHG, then it would trigger PSD permitting under EPA Authority. The Project-related increases are:

Pollutant	Project-Related Increase in Emissions (T/yr)	Major Modification (Significance) Threshold (T/yr)	Major Source Threshold (T/yr)
CO_2e	>100,000	75,000	100,000
GHG (Mass)	>250	100	250
CO	52.35	100	N/A[a]
NO_X	10.12	40	N/A[a]
PM	9.56	25	N/A[a]
PM_{10}	9.56	15	N/A[a]
$PM_{2.5}$	9.56	10	N/A[a]
SO_2	1.04	40	N/A[a]

[a] Not applicable for EPA permitting authority. If the Project were to constitute a new major source for this pollutant, then TCEQ would be the PSD permitting authority.

As shown above, the Project constitutes a major modification and new major source for GHG. Therefore, the Project triggers GHG PSD permitting under EPA authority. The Project does not constitute a major modification for any non-GHG criteria air pollutant. Therefore, GHG is the only pollutant undergoing PSD review under EPA authority.

Accordingly, per EPA's direction, Lone Star is submitting this PSD permit application to EPA for GHG and has submitted a separate application to TCEQ for the remaining criteria pollutants.

2 PROCESS/PROJECT DESCRIPTION

This section provides an overview of the proposed Project location and operations that result in GHG emissions. As stated previously, the proposed Project includes construction of the FRAC III Plant at the Site. Figure 2-1 is an area map for the Site, showing the fence line and surrounding area. As shown in Figure 2-1, there are no schools within 3,000 feet of the proposed Project. Figure 2-2 is a map showing the Site location and the nearest federal Class I areas (i.e., all of which are over 500 kilometers [km] from the Site). Figures 2-3 and 2-4 are plant layout diagrams showing the locations of the proposed emission sources.

Figure 2-5 is a simplified process flow diagram for the FRAC III Plant operations. The following paragraphs present the FRAC III Plant's proposed operating configuration, which will be in continuous year-round operation (i.e., 8,760 hours per year [hr/yr]).

2.1 Amine Unit / Thermal Oxidizer

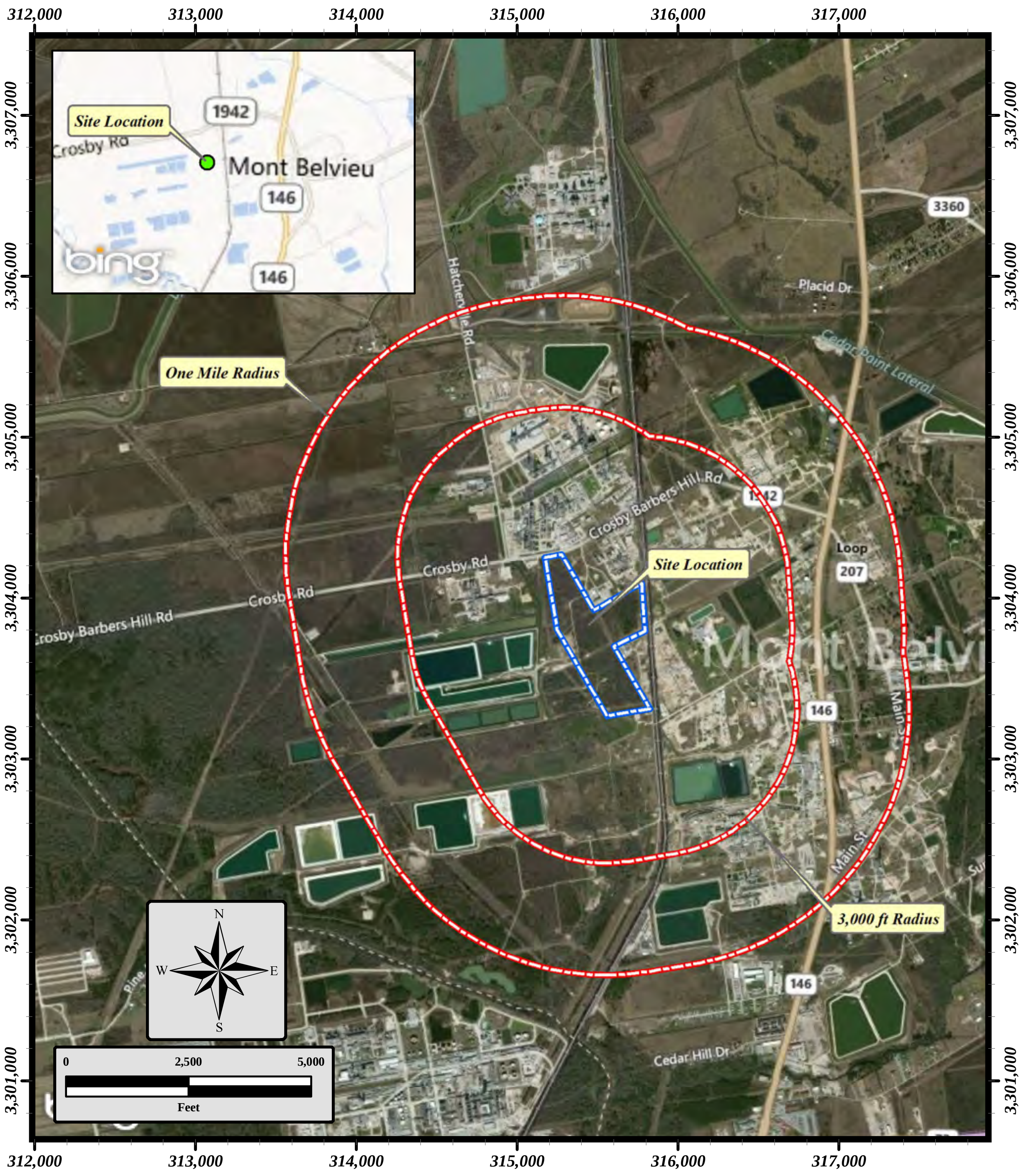
NGL feed will enter the FRAC III Plant and pass through a closed loop amine unit (Facility Identification Number [FIN]: 3HT16.005). The amine unit will use amine contactors to remove CO_2 and the small amount of hydrogen sulfide (H_2S) from the NGL stream. Other hydrocarbons (VOC) will be absorbed in this process as well. The saturated (rich) amine will enter a flash tank where gaseous vapors will be flashed and recycled back to the plant fuel gas system.

After the flash tank, the liquid stream (rich amine) will be routed to an amine regenerator, where heat from the FRAC III Plant's heating oil system will volatilize the remaining CO_2, H_2S and VOC from the rich amine stream. The lean amine will be returned to the amine contactors for reuse while the waste gas from the amine regenerator will be routed to the associated thermal oxidizer (FIN: 3SK25.002) for combustion of VOC and H_2S.

The thermal oxidizer (FIN: 3SK25.002) will have a fuel firing rate of five (5) million British thermal units per hour (MMBtu/hr) and a destruction efficiency (DRE) of 99.9% for VOC and H_2S, which it will achieve by maintaining a combustion chamber temperature of at least 1,400 °F. GHG emissions from the thermal oxidizer will result from waste gas and fuel gas combustion as well as amine unit CO_2 pass-through.

In addition to the regenerator vent emissions that will be controlled by the thermal oxidizer, the amine unit will result in a small amount of GHG emissions (i.e., CH_4) from fugitive equipment component leaks (FIN: 3FUG), which will be controlled by implementation of an LDAR program.

MSS emissions associated with the amine unit are addressed later in this section.



Grid Presented is UTM Zone 15, NAD 1983

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FIGURE 2-1 AREA MAP
Lone Star NGL Fractionators LLC
Mont Belvieu Gas Plant
FRAC III Project GHG PSD Air Permit Application
TITAN Project No. 84800475-08.001
June 2013
from USGS Quadrangle Mont Belvieu, Texas
Ground Condition Depicted April 2012
Digital Data Courtesy of ESRI Online Datasets

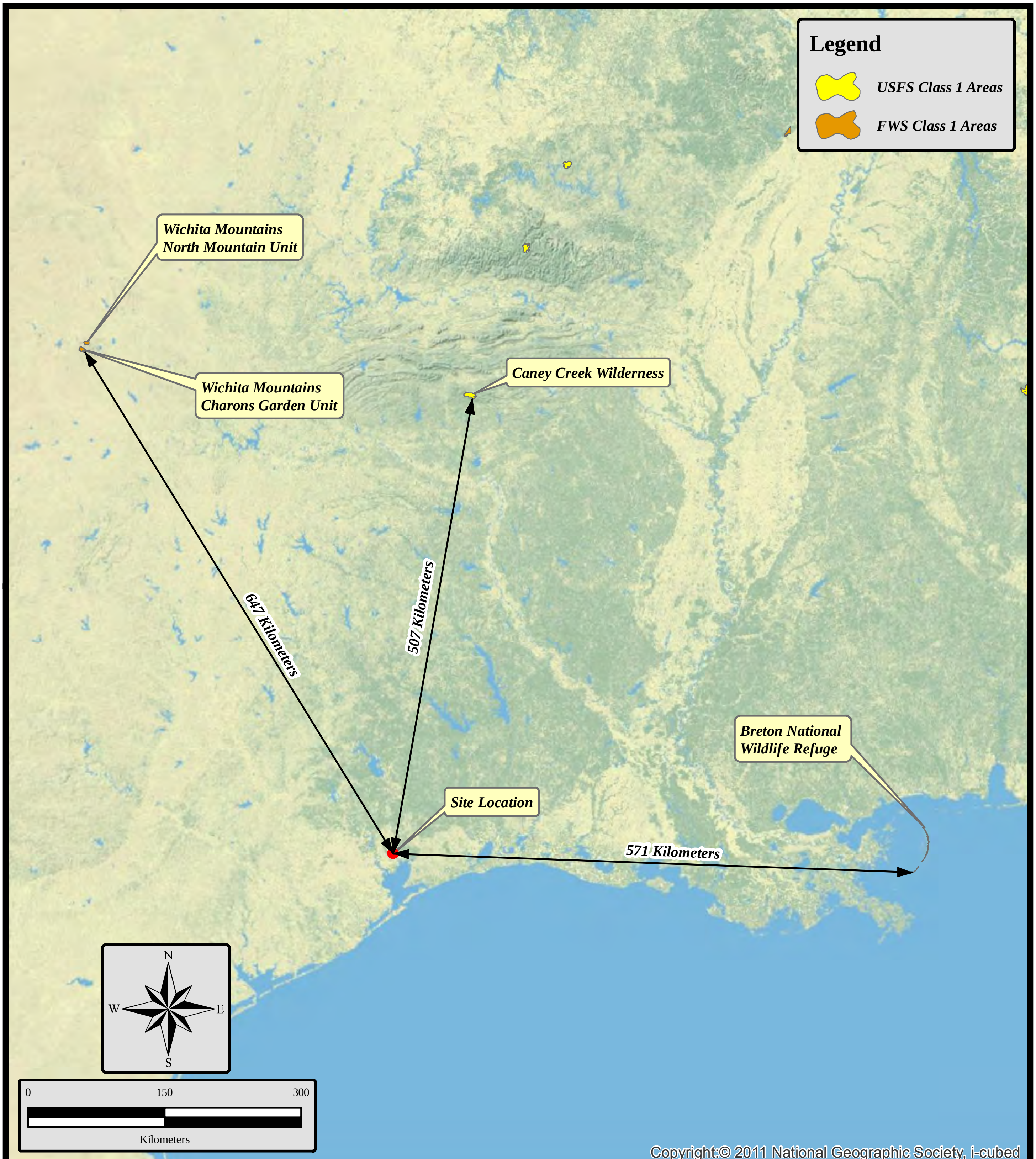

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FIGURE 2-2 CLASS 1 AREAS

Lone Star NGL Fractionators LLC
Mont Belvieu Gas Plant
FRAC III Project GHG PSD Air Permit Application
TITAN Project No. 84800475-08.001
June 2013
from USGS Quadrangle Harmaston, Texas
Digital Data Courtesy of ESRI Online Datasets

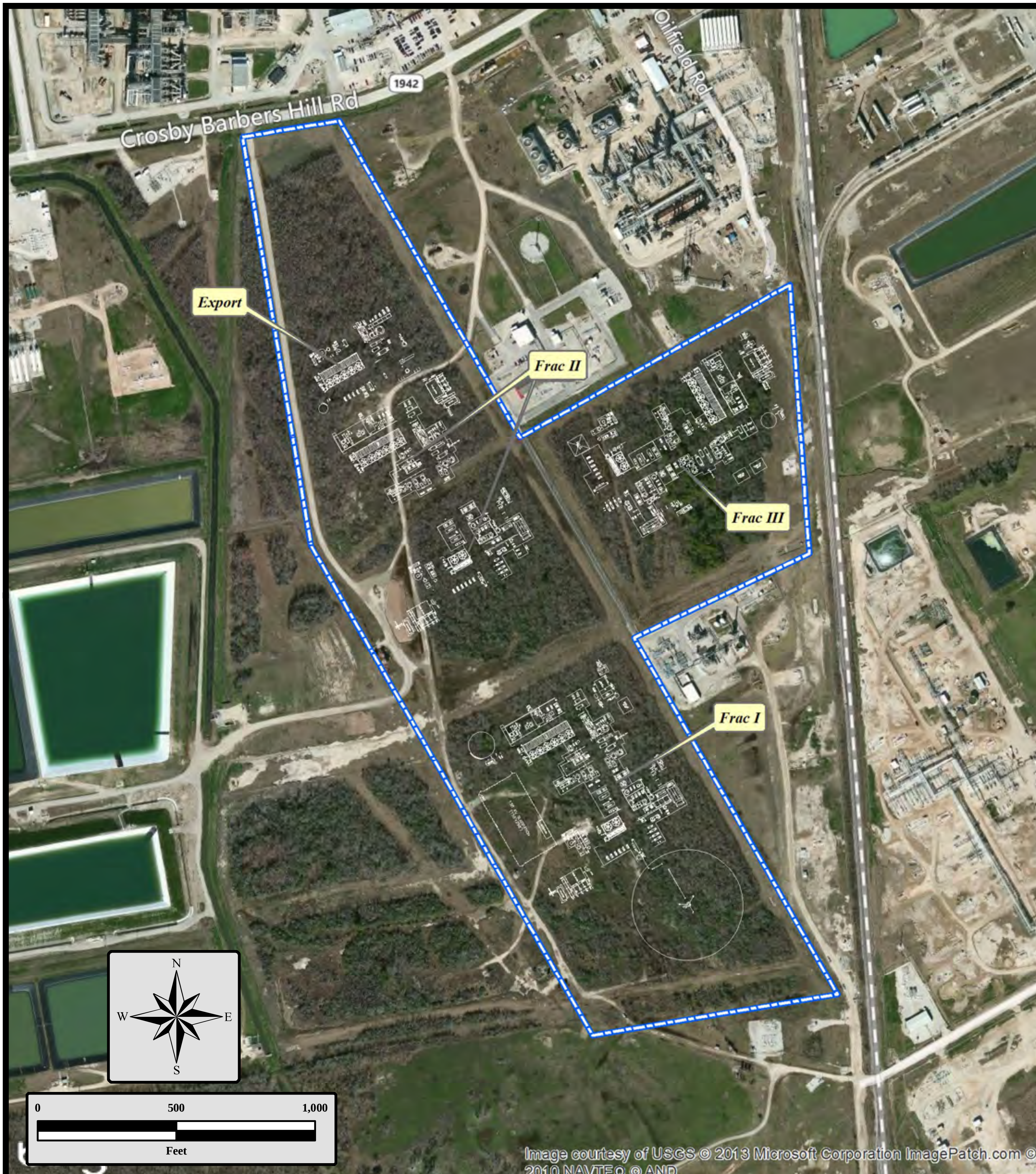

FIGURE 2-3 PRELIMINARY SITE LAYOUT

Lone Star NGL Fractionators LLC
Mont Belvieu Gas Plant
FRAC III Project GHG PSD Air Permit Application
TITAN Project No. 84800475-08.001
June 2013

from USGS Quadrangle Mont Belvieu, Texas
Ground Condition Depicted April 2012
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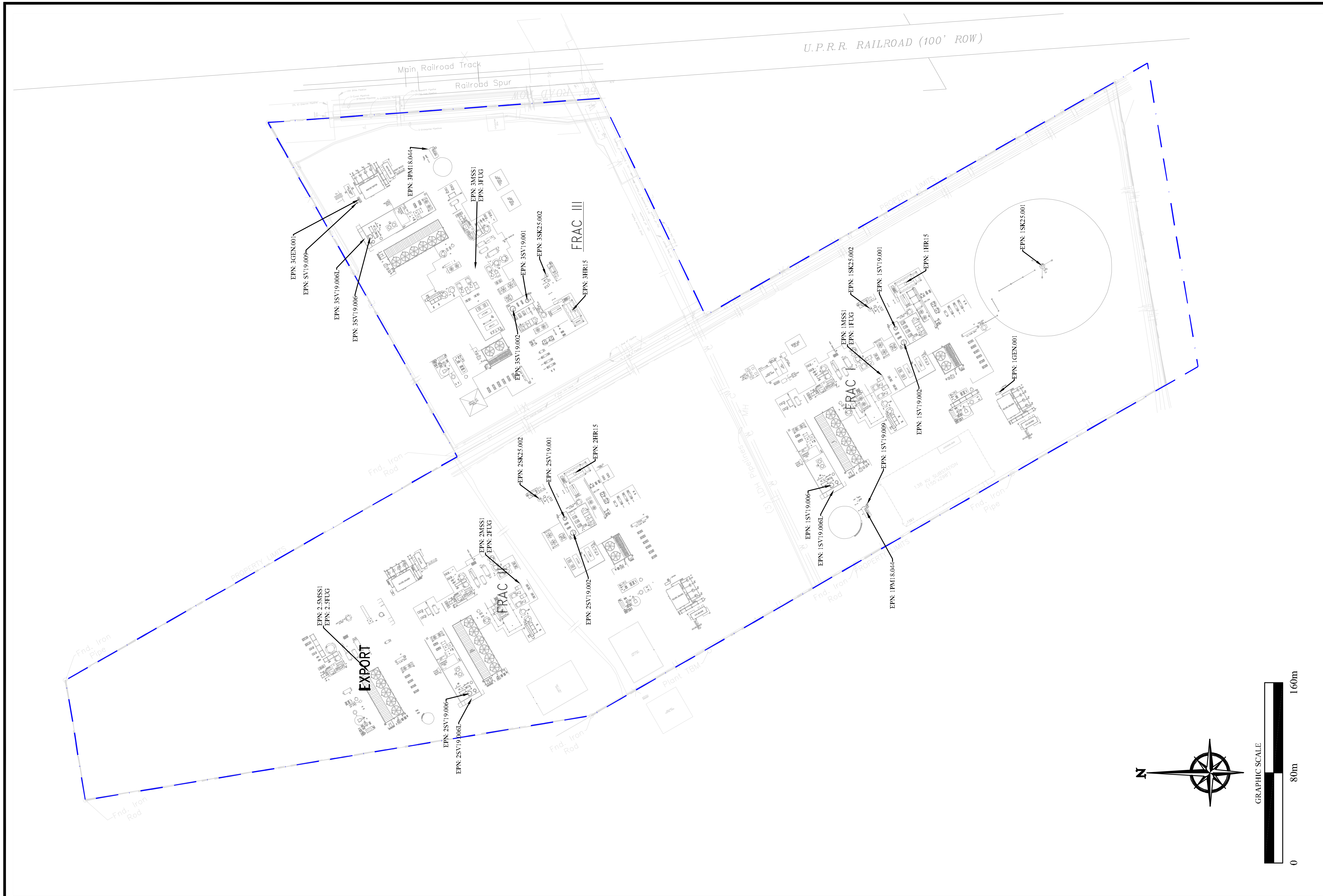

FIGURE 2-4

PRELIMINARY SITE LAYOUT

Lone Star NGL Fractionators LLC
Mont Belvieu Gas Plant
FRAC III Project GHG PSD Air Permit Application

DESIGNED BY: TEI	DETAILED BY: LLA	CHECKED BY: SE
FILE NAME: T:\Lone Star NGL\MontBel\475-08.001\Fig\CAD		
DATE: 06/2013	PROJECT NO.: 84800475-08.001	PLOT SCALE: 1"=100m
DRAWING NO.: TEI-0000	REVISION: 0	FIGURE: 2-3

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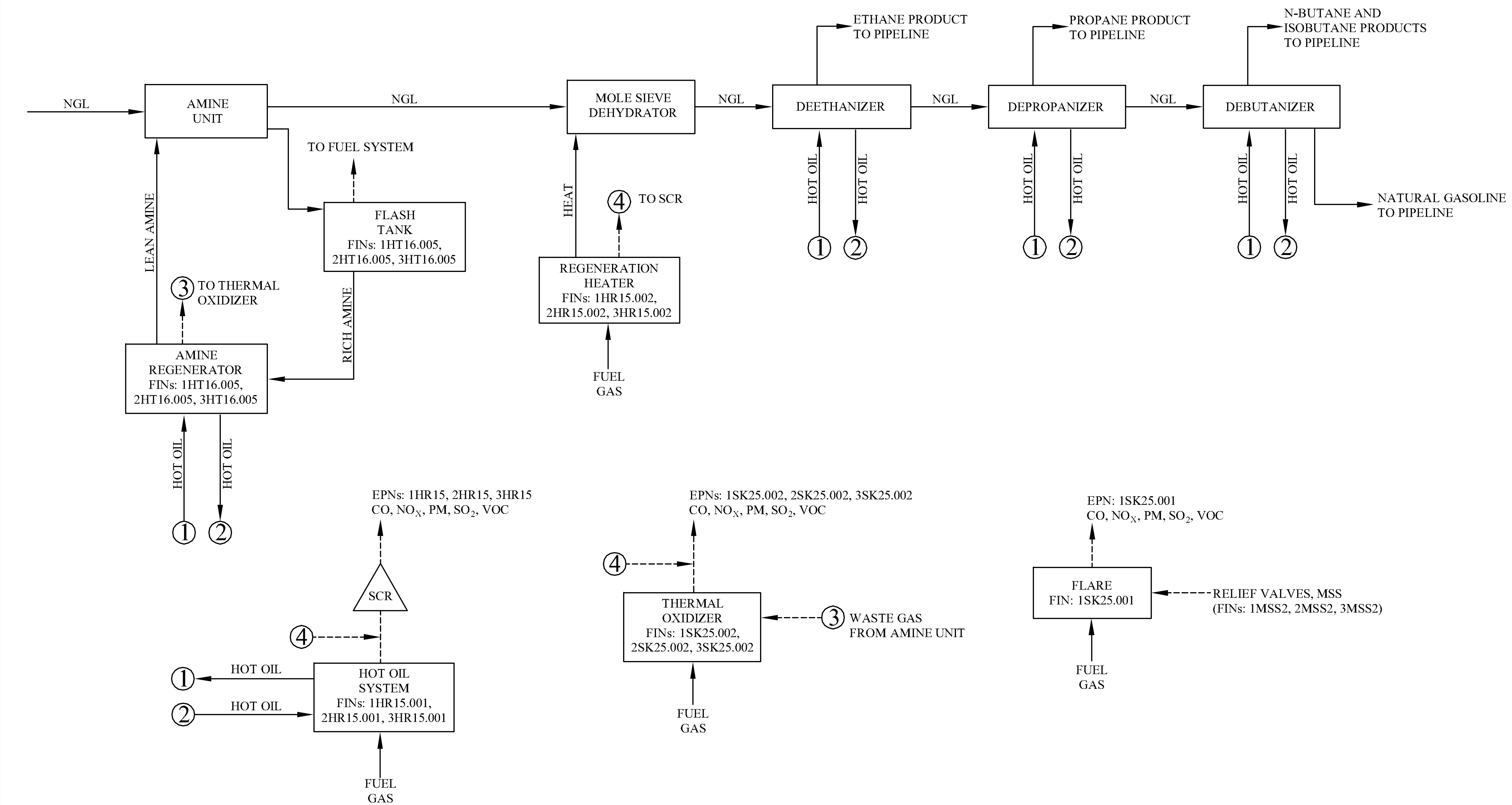

NOTES

Fuel can be NG or Ethane

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FIGURE 2-5
SIMPLIFIED PROCESS FLOW DIAGRAM

Lone Star NGL Fractionators LLC
Mont Belvieu Gas Plant
FRAC III Project
GHG PSD Air Permit Application

DESIGNED BY:	DETAILED BY:	CHECKED BY:
TEI	LLA	SE
FILE NAME: T:\Lone StarNGL\MontBelvieu\Frac 3\Figs\CAD		
DATE: 06/2013	PROJECT NO.: 84800475-08.001	PLOT SCALE: N.T.S.
DRAWING NO.: TEI-0000	REVISION: 1	FIGURE: 2-5

2.2 Hot Oil System

The purpose of the FRAC III Plant hot oil system will be to provide heat to the Project processes, including the amine unit. By using oil, the heat will be transferred to the Project processes with a minimum loss of heat to the oil, allowing for a quicker recovery to the desired temperature in a closed-loop system. The hot oil system will be a network of piping that circulates hot oil through, and provides heat as needed in, various areas of the FRAC III Plant.

The hot oil system will utilize a 215 MMBtu/hr gas-fired heater (FIN: 3HR15.001). The heater will be equipped with Next Generation Ultra-Low NO_X Burners (NGULNB), or manufacturer equivalent (e.g., John Zink COOLstar burners), and will be further controlled by an SCR system. Periods of startup and shutdown will be limited to one hour for each type of event and 50 hr/yr for all MSS hours combined.

The combustion of fuel gas (pipeline quality natural gas and/or ethane product) in the hot oil heater will result in combustion-related GHG emissions. The heater will not be expected to have GHG emissions in excess of the proposed allowable emission rates during periods of startup, shutdown, or maintenance, because the fuel firing rate will be below the maximum rate and proper combustion commences very quickly.

2.3 Molecular Sieve Dehydration Unit

From the amine unit, the NGL will be routed through a molecular sieve dehydration unit, where the water content in the NGL will be reduced. A regeneration heater (FIN: 3HR15.002) will heat a small amount of NGL feed vapor that will be slip-streamed as needed to regenerate the sieve beds. The gas will then be routed back into the system inlet. There will be two (2) beds in the molecular sieve design, and one (1) bed will be regenerated at a time. The molecular sieve unit will not have vents to the atmosphere, and wet gas from the regenerated bed will be routed back to the system. Therefore, the only GHG emissions from this unit will be from fugitive equipment component leaks (FIN: 3FUG), which will be controlled by a LDAR program.

The regeneration heater (FIN: 3HR15.002) will be a 59 MMBtu/hr gas-fired heater. The heater will be equipped with NGULNB, or manufacturer equivalent, and will be further controlled by an SCR system. Between regeneration cycles, the heater's firing rate is reduced to a maintenance level. However, to conservatively estimate emissions, Lone Star has assumed the heater fires at maximum capacity year-round (8,760 hr/yr). Periods of startup and shutdown will be limited to one hour for each type of event and 50 hr/yr for all MSS hours combined.

The combustion of fuel gas in the regeneration heater will result in combustion-related GHG emissions. The heater will not be expected to have GHG emissions in excess of the proposed allowable emission rates during periods of startup, shutdown, or maintenance, because the fuel firing rate will be below the maximum rate and proper combustion commences very quickly.

2.4 NGL Fractionation

NGL leaving the dehydration unit will be fed to a series of trayed columns for separation into constituent product gases. At the bottom of each column will be a reboiler that will be heated by the plant's heating oil system. As the NGL stream enters a column in the middle, the reboiler will vaporize a portion of the feed to produce stripping vapors rising inside the column. This stripping vapor will rise up through the column contacting down-flowing liquids allowing for the fractionation of the liquids. Vapor leaving the top of the column will enter a condenser where heat is removed by a cooling medium and the vapor condensed. Liquid will be returned to the column as reflux to limit the loss of heavy components overhead. The product leaving the lower part of the column will have the highest boiling point, whereas the hydrocarbon leaving the top of the column will have the lowest boiling point.

The separated streams (ethane, propane, butanes, and natural gasoline) will be sent via pipeline to off-site storage for pending sale to customers.

This process will not have vents to the atmosphere. Therefore, the only emissions associated with this process will be from fugitive equipment component leaks (FIN: 3FUG), which will be controlled by an LDAR program. Certain piping leaks, MSS vents, and pressure relief valves will be routed to the Plant Flare, which will result in combustion-related GHG emissions at the flare.

Thus, no GHG emissions will be generated from processes downstream of the amine unit, except emissions from process heaters and fugitives, because the processes will be closed systems and most, if not all, CO_2 is removed at the amine unit. Additionally, very little, if any, methane is contained in the NGL that will enter the plant.

2.5 Flare

The existing Plant Flare (FIN: 004-FLARE in Permit No. PSD-TX-93813-GHG, but changed to FIN 1SK25.001 for TCEQ Permit No. 110274) will be used to control emergency process releases and streams resulting from MSS activities from FRAC III Plant processes. No process streams (e.g., amine regenerator waste gas) will be routed to the flare during normal operation.

Combustion-related GHG emissions from the flare will result from the combustion of MSS and fugitive hydrocarbon streams. This PSD permit application addresses only the emission increase at the existing flare associated with the combustion of the FRAC III Plant process streams. The flare has a hydrocarbon destruction and removal efficiency (DRE) of 98%.

2.6 Diesel-Fired Engines

The FRAC III Plant will have two emergency diesel generators (FINs: 3GEN.001 and 3GEN.002) for use in the case of loss of electrical power and an emergency diesel fire water pump (FIN: 3PM18.044) in case of fire. These engines are operated in nonemergency situations for up to 36 hr/yr for testing and maintenance to ensure reliability during emergency situations. The combustion of diesel in the emergency engines will result in combustion-related GHG emissions.

2.7 Equipment Components (Piping)

As stated previously, the FRAC III Plant processes may result in fugitive emissions of GHG pollutants, including CO_2 and CH_4, from piping equipment leaks. NGL and the Plant product streams downstream of the amine unit contain very little, if any, CO_2 and CH_4. The FRAC III Plant fuel gas system contains CH_4, as CH_4 is the primary component of natural gas. The piping components that may leak include valves, flanges, pump seals, etc. Lone Star will be implementing the TCEQ 28LAER LDAR program for the Site's VOC streams and fuel gas stream to control leaks, thereby controlling GHG emissions.

As discussed above, the existing air-assisted Plant Flare (FIN: 1SK25.001) will control emergency process releases, emissions resulting from maintenance, startup, and shutdown activities (FIN: 3MSS2), and piping vents (e.g., seal vents and produced water flash pot vents) (FIN: 3PV). The purpose of the flare is to reduce VOC emissions, and that control results in corresponding GHG emissions increases.

2.8 MSS Activities

Certain MSS activities (specifically the FRAC III Plant startup activities) will not result in excess GHG emissions to the atmosphere. During startup, the FRAC III Plant will produce off-specification products while the columns are initiated and brought online. During this process, the off-specification products will be injected and stored underground (i.e., with no emissions to atmosphere) and returned to the process once the FRAC III Plant has reached normal operation. The only emissions associated with this activity will be fugitive piping leaks, which are accounted for in the normal operations emission rates (FIN: 3FUG) discussed above.

Certain MSS activities (FIN: 3MSS2) will be of a nature such that they can be captured and routed to the Plant Flare (FIN: 1SK25.001) discussed above, as described in detail below:

- FRAC III Plant shutdown: During shutdown, the FRAC III Plant equipment will remain under pressure with materials in the system, with the exception of the Deethanizer. The refrigerated process is required to vent during shutdown, because the materials expand as the temperature rises. During an extended outage, which lasts approximately one day, the Deethanizer column will vent to flare until the vapor pressure of the materials reach the design pressure rating of the equipment. These blowdown emissions will be routed to flare.

- Inlet filter changeout: The Inlet Feed Filter and Inlet Feed Coalescer will remove solids and aqueous liquid from the NGL feed to the FRAC III Plant. The solids will be mostly comprised of pipeline dust and rust. The liquids will be mostly water and other immiscible liquid in the hydrocarbon stream. The filters will be designed to be operated continuously during normal operations, and will be scheduled for changeout during normally scheduled maintenance intervals.

  Ethane and nitrogen will be used to purge NGL from the filters prior to changeout. The purge stream will be vented to flare. Water will be drained from the filters prior to opening the equipment to atmosphere. After changeout, the filters will be first pressurized with nitrogen then filled with NGL. During initial filling, the filters will be vented to flare.

- Normal Pump/Compressor Maintenance: Rotating equipment will be designed to operate continuously for a minimum of three (3) years before maintenance, per API guidelines, requiring isolation from the process. Therefore, the rotating equipment maintenance intervals will be coordinated with the scheduled shutdown of the FRAC III Plant. When necessary, the equipment will be vented (blown down) to flare and purged with nitrogen prior to opening to atmosphere. When bringing the equipment back online after maintenance, the equipment will be filled with nitrogen then NGL, with emissions being vented to flare until the equipment is back in normal operation.

  Hydrocarbon pumps will contain double mechanical shaft seals with a barrier fluid monitoring system to alert when seal failure is occurring. Hydrocarbon pumps are 100% spared, such that when a failure occurs, the standby pump will be put in service, and the failed pump will be taken out of service for repair.

  Compressor design will incorporate shaft sealing systems that will capture/prevent hydrocarbon emissions. This will be accomplished by double mechanical seals with barrier protection, with an inert purge or other approved method. Compressors will be vented to the flare system and nitrogen purged prior to being opened to the atmosphere for maintenance. When returning to service, the equipment will be purged with nitrogen then filled with process material prior to startup. These emissions will also be vented to flare.

- Liquid Meter Proving: There will be several meters installed as part of the FRAC III Plant. These meters will be located in a common area. Liquid and gas meters will require periodic calibration and/or proving. The calibration will be accomplished by use of a prover system. The liquid meter system will be connected to the flare for control of VOC emissions. Each meter/prover connection will be capable of being purged to the flare system. The prover can be operated on multiple meters sequentially without purging, reducing VOC vents to flare.

Certain MSS activities result in emissions to atmosphere (FIN: 3MSS1), including:

- replacement of analyzer filters/screens,
- filter/meter maintenance/replacement (fuel gas meter proving), and
- spare pump startup.

These MSS activities will result in very low GHG emissions, due to their infrequent occurrence.

2.9 Non-GHG Sources

The FRAC III Plant will also have process equipment that will not be sources of GHG emissions. The equipment includes:

- Cooling water heat exchange system – a vapor mist cooling water heat exchange system will be utilized to cool process piping. The water mist will flow over the piping and will be collected for recycle. This equipment will not be a source of air emissions.
- Tanks – proposed process tanks will store fresh amine, heating oil (for the hot oil system), diesel, and slop water. Additionally, a pressurized ammonia tank will be used to store the ammonia to be injected into the SCR NO_X control system for the two heaters. None of the tanks will result in GHG emissions.
- Loading – slop water will be trucked off-site via atmospheric loading. This loading operation will not emit GHG.
- Electric-driven compressors and pumps – as process gas and/or liquid travels through pipelines and the plant processes, it loses pressure or energy due to the friction on the pipe walls or as part of the process. Electric-driven compressors and pumps will be utilized to maintain necessary gas or liquid pressure. These compressors and pumps will not be sources of pollutant emissions.
- Certain MSS Activities result in no GHG emissions to atmosphere (FIN: 3MSS1), as described below:
    - compressor maintenance,
    - seal inspections and other tank inspection activities, and
    - maintenance on pumps.

3 AIR EMISSIONS

Section 3.1 describes the GHG emissions associated with the proposed FRAC III Plant. Section 3.2 describes the BACT to be implemented at the FRAC III Plant. Section 3.3 describes the emission calculation methodologies used to quantify the FRAC III Plant GHG emission rates.

3.1 Project Emissions

Table B-1 in Appendix B summarizes the Project-related GHG pollutant emission rates. As shown on Table B-1, the Project triggers PSD review for GHG. Detailed GHG emissions calculations are included in Appendix B to this document.

3.2 Emissions Controls (BACT)

The EPA and TCEQ require the application of BACT for the control of each regulated pollutant emitted from new stationary sources. The equipment and activities in this permit application will meet BACT requirements for GHG. Due to the complex BACT analysis required for a PSD application, an entire section (Section 4) is dedicated to presenting BACT for the Project GHG sources.

3.3 Emission Rate Calculation Methodologies

The following subsections briefly describe the methodologies used to estimate the maximum annual GHG emission rates from the FRAC III Plant's proposed emission sources. Emissions from the Project's sources were estimated using published emission factors and equations in 40 CFR Part 98, equipment vendor-provided information, process simulation software, or other EPA approved methods. Detailed emission rate calculations are included as Appendix B to this document, and documentation in support of the calculations has been included in Appendices C and E, as appropriate.

3.3.1 Process Heaters

The FRAC III Plant will employ a gas-fired hot oil heater (FIN: 3HR15.001) and mole sieve regenerator heater (FIN: 3HR15.002) whose exhausts will be routed to a common SCR abatement device (EPN: 3HR15). GHG emissions from the heaters will be generated as a result of combustion of fuel gas. Annual GHG mass emission rates are estimated by applying the emission factors in Tables C-1 and C-2 of 40 CFR Part 98 Subpart C to the maximum annual heat input and summing the resultant emission rates. These emission factors are:

- CO_2: 53.02 kg/MMBtu
- CH_4: 0.001 kg/MMBtu
- N_2O: 0.0001 kg/MMBtu

The maximum annual heat input assumes that the maximum hourly heat input rate (215 MMBtu/hr for the hot oil heater and 59 MMBtu/hr for the regenerator heater) occurs 8,760 hr/yr.

The annual CO_2e emission rates are estimated by applying the global warming potential (GWP) of each GHG pollutant to its mass emission rate prior to summing. The GWP for each pollutant from Table A-1 of 40 CFR Part 98, Subpart A is:

- CO_2: 1
- CH_4: 21
- N_2O: 310

Please refer to the combustion-related GHG emission calculation sheet in Appendix B for example calculations.

3.3.2 Thermal Oxidizer

A gas-fired thermal oxidizer (FIN: 3SK25.002) will be used to control the waste gas vent stream from the amine unit regenerator vent. GHG emissions from the thermal oxidizer will result from fuel gas combustion and waste gas combustion.

Annual GHG mass emission rates from fuel gas combustion in the thermal oxidizer are estimated by applying the emission factors in Tables C-1 and C-2 of 40 CFR Part 98 Subpart C to the maximum annual heat input and summing the resultant emission rates. The maximum annual heat input from fuel firing assumes that the maximum hourly fuel firing rate (5 MMBtu/hr) occurs 8,760 hr/yr.

Annual GHG mass emission rates from waste gas combustion in the thermal oxidizer are estimated by summing the following:

- **Un-combusted CO_2:** CO_2 in the waste gas stream that passes through the thermal oxidizer (amine unit waste gas). Direct CO_2 emissions from the waste gas were estimated based on the vendor provided data for the composition of the thermal oxidizer inlet stream;
- **Combustion CO_2**: CO_2 generated from combustion of the waste gas, which is calculated using 40 CFR §98.233, equations W-21 and W-36. CO_2 emissions calculations use the waste gas mass flow rate from vendor provided data and the number of carbon atoms in the gas stream with a 99.9% conversion for the thermal oxidizer combustion efficiency;
- **Un-combusted CH_4:** the post-control methane emission rate, or that portion that is not combusted in the thermal oxidizer (99.9% destruction efficiency); and
- **Combustion N_2O:** N_2O generated from combustion of the waste gas, which is calculated using 40 CFR §98.233, equation W-40 and the waste gas heat rate provided by the vendor.

The annual CO_2e emission rates are estimated by applying the GWP of each GHG pollutant to its mass emission rate prior to summing.

Please refer to the thermal oxidizer waste gas and combustion-related GHG calculation sheets in Appendix B for example calculations and the vendor-provided thermal oxidizer inlet stream composition in Appendix C.

3.3.3 Flare

The Plant Flare's existing unmodified GHG emissions include:

- combustion-related emissions from firing pilot gas (FIN: 1SK25.001; EPN: 1SK25.001), which were authorized under TCEQ Standard Permit No. 93813 and predate the GHG Tailoring Rule;
- combustion-related emissions from firing MSS and piping vent emissions from FRAC I Plant and Export FRAC, (FIN: 1SK25.001; EPN: 1SK25.001) , which were authorized under TCEQ Standard Permit No. 93813 and predate the GHG Tailoring Rule;
- combustion-related emissions from firing MSS and piping vent emissions from FRAC I Plant, FRAC II Plant, and Export FRAC (FIN: 1SK25.001; EPN: 1SK25.001), which were authorized under TCEQ Standard Permit No. 93813 and EPA Permit No. PSD-TX-93813-GHG; and
- uncontrolled MSS and piping vent emissions (i.e., 1% for methane) from FRAC I Plant, FRAC II Plant, and Export FRAC (FINs: 1MSS2, 1PV, 2MSS2, 2PV, 2.5MSS2, and 2.5PV; EPN: 1SK25.001), which were authorized as noted above for combustion-related emissions.

The FRAC III Plant will add the following to the Plant Flare's total GHG emission rate:

- combustion-related emissions from firing MSS and piping vent emissions from FRAC III Plant (FIN: 1SK25.001, EPN: 1SK25.001) and
- uncontrolled MSS and piping vent emissions (i.e., 1% for methane) from FRAC III Plant (FINs: 3MSS2 and 3PV; EPN: 1SK25.001).

As stated previously, this application is only addressing FRAC III Plant MSS and fugitive activities. No process streams (e.g., amine regenerator waste gas) will be routed to the flare during normal operation.

The flow rate and composition of MSS emissions as well as the duration and frequency of MSS events were estimated based on two events per year. The flow rate and composition of the piping vent fugitives were estimated based on 8,760 hr/yr.

Emissions of organic species routed to the flare were converted to emissions of CO_2 assuming a 100% conversion rate. CO_2 conversion factors for organic components were estimated by dividing the product of the molecular weight of CO_2 and the mass fraction of the component by the molecular weight of the component. The mass fractions of the components were provided by the vendor.

GHG mass-based emissions and CO_2e emissions are estimated as follows:

- **GHG Mass-Based Emissions:** The mass-based emissions of CO_2 were calculated based on the above operating parameters and emission factors, molecular weights of organic components, and a mass conversion factor. The total emission rate of GHG from MSS and fugitive activities is equal to the sum of GHG emissions from each organic component of the vent streams. No other greenhouse gas emissions are generated.

- **CO_2e Emissions**: The CO_2e emissions were calculated using the mass-based emissions of each GHG pollutant and applying the GWP values in Table A-1 of 40 CFR Part 98, Subpart A prior to summing.

Please refer to the flare waste gas and combustion-related GHG emission calculation sheets in Appendix B for example calculations.

3.3.4 Piping Equipment Leaks

Fugitive emissions (FIN: 3FUG) of CO_2 and CH_4 occur from various piping equipment, including valves, connectors, pumps, and compressors in gas service. These fugitives will occur in the inlet NGL, residue gas, fuel gas system, and molecular sieve regeneration gas streams. Speciation of the fugitive GHG emissions is based on the relative constituent concentrations in the various process streams.

Hourly emission rates from equipment leaks are calculated by applying emission factors from the TCEQ draft guidance document, "Air Permit Guidance for Chemical Sources: Equipment Leak Fugitives," dated October 2000, to the number of components. Annual emissions are estimated by assuming the maximum hourly emission rate could occur 8,760 hr/yr.

Lone Star will be implementing the 28LAER LDAR Program for the FRAC III Plant VOC and fuel gas streams. Control efficiencies, which are listed by equipment type in the TCEQ guidance document "Control Efficiencies for TCEQ Leak Detection and Repair Programs" (APDG 6129v2), dated July 2011, are applied to the emissions as appropriate.

CO_2 and methane emissions are estimated by applying each constituent's concentration in the gas/liquid stream to that stream's total emission rate. The annual CO_2e emission rates are estimated by applying the GWP of each GHG pollutant to its mass emission rate prior to summing.

Please refer to Appendix B for detailed GHG emission rate calculations.

3.3.5 Diesel-Fired Engines

The FRAC III Plant will include two diesel-fired emergency generator engines (FINs: 3GEN.001 and 3GEN.002) and a diesel-fired firewater pump engine (FIN: 3PM18.044). The combustion of diesel in the emergency engines will result in combustion-related GHG emissions. The generators and pump non-emergency operation will be limited to a maximum of 36 hours per year each. Annual GHG mass emission rates are estimated based on using vendor specifications (447 kW) to determine the maximum annual heat input and applying the emission factors in Tables C-1 and C-2 of 40 CFR Part 98 Subpart C for diesel. These emission factors are:

- CO_2:	73.96 kg/MMBtu
- CH_4:	0.003 kg/MMBtu
- N_2O:	0.0006 kg/MMBtu

The annual CO_2e emission rates are estimated by applying the global warming potential (GWP) of each GHG pollutant to its mass emission rate prior to summing.

Please refer to the combustion-related GHG emission calculation sheet in Appendix B for example calculations.

3.4 Emissions Monitoring and Recordkeeping

In order to demonstrate compliance with the proposed GHG emission rates, Lone Star proposes to monitor the following parameters and summarize the data on a calendar month basis:

- operating hours for all air emission sources;
- the fuel gas usage for all combustion sources, using continuous fuel flow monitors (a group of equipment can utilize a common fuel flow meter, as long as actual fuel usage is allocated to the individual equipment based upon actual operating hours and maximum firing rate), which will be calibrated on an annual basis;
- the waste gas flow rates to the flare and thermal oxidizer;
- the daily NGL processing rate for the FRAC III Plant;
- the frequency, occurrence, cause, duration, and associated air emissions for each MSS event;
- LDAR program monitoring results, as well as repair and maintenance records.

At least once a year, Lone Star will obtain an updated analysis of the fuel gas and NGL inlet to document the CO_2 and methane content. This analysis will be considered to be representative of the gas streams for the calendar year during which it was taken.

Lone Star will maintain the daily production volumes of natural gas liquids produced for the FRAC III Plant in barrels per day (bbl/day).

At least once per quarter, Lone Star will obtain an updated analysis of the waste gas from the amine unit. This analysis will be considered to be representative of the gas streams for the quarter during which it was taken and will be used to estimate the amine unit waste gas vent emissions, higher heating value (HHV), and lower heating value (LHV).

Lone Star will install and operate a continuous emissions monitoring system (CEMS) on the SCR stack (EPN: 3HR15). The CEMS will monitor CO, NO_X, NH_3, and oxygen (O_2), with a monitor downtime of no more than 5% of the annual operating hours of the heaters. The CEMS will be designed and operated in accordance with 40 CFR Part 60, Appendix F.

Lone Star will install and operate a temperature recording device with an accuracy of the greater of ± 0.75% of the temperature being measured in °C or ± 2.5°C on the thermal oxidizer. The combustion temperature of the thermal oxidizer will be continuously monitored and recorded when waste gas is being combusted. Monitor downtime will not exceed 5% of the annual operating hours of the thermal oxidizer.

Finally, Lone Star will design and operate the flare in accordance with 40 CFR §60.18, including specifications for minimum heating value of the waste gas, maximum tip exit velocity, and pilot flame monitoring. Lone Star considers an infrared monitor to be equivalent to a thermocouple for flame monitoring purposes.

4 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

The PSD regulation requirements of 40 CFR §52.21(j) require that BACT be used to minimize the emissions of pollutants subject to PSD review from a new major source or a modification to an existing major source. BACT is typically evaluated on a pollutant by pollutant basis and on an emission unit by emission unit basis.

This section presents the GHG BACT analysis for the Project. Section 4.1 provides background information for the BACT analysis. Section 4.2 provides an overview of the BACT review process used in this application. Section 4.3 addresses BACT for GHG emissions.

4.1 Background

The GHG sources associated with the Project are summarized in Table 4-1. As shown on Table 4-1, the Project GHG sources emit GHG by either combustion or by GHG in the process streams, and the GHG is emitted either through stacks or as fugitive emissions.

All compressors will be powered by electric driven engines. All non-emergency combustion sources at the Site will be fired on fuel gas (pipeline-quality natural gas and/or ethane product).

The overall energy efficiency of the sources through technologies, processes, and practices at the FRAC III Plant should be included in a BACT determination. In general, a more energy-efficient technology burns less fuel than a less energy efficient technology on a per-unit-of-output basis. Energy efficient technologies in the BACT analysis help reduce the production of combustion-related GHG and other regulated pollutants (CO, NO_X, $PM/PM_{10}/PM_{2.5}$, SO_X, and VOC). Because all the equipment associated with this project is new, it will be outfitted with the best engineering design and with latest technology that are reasonably available to ensure the best available energy efficiency for the FRAC III Plant's intended processes.

TABLE 4-1

PROJECT GHG EMSSION SOURCES

GHG PSD AIR PERMIT APPLICATION TO EPA

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

Equipment Type	GHG Source Type	Exhaust Type
Heaters (< 250 MMBtu/hr, fired on natural gas and/or ethane)	Combustion Source	Stack
Plant Flare (intermittent control of certain MSS and piping emissions)	Combustion Source	Stack
Thermal Oxidizer (control of Amine Unit Regenerator Vent)	Combustion Source	Stack
Amine Unit	Process Source	Stack
Emergency Generators and Firewater Pump (< 700 hp each, diesel-fired)	Combustion Source	Stack
Piping Fugitives	Process Source	Fugitive

4.2 BACT Review Process

EPA recommends that the *1990 Draft New Source Review Workshop Manual* be used to determine BACT for PSD pollutants. According to this document, BACT determinations are made on a case by case basis using a "top-down" approach, with consideration given to technical practicability and economic reasonableness. Section 169(3) of the Clean Air Act defines BACT as follows:

> "The term BACT means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under the Clean Air Act emitted from or which results from any major emitting facility, which the permitting authority, on a case by case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. In no event shall application of BACT result in emissions of any pollutants which will exceed any applicable standard established pursuant to section 111 (NSPS [New Source Performance Standards]) or 112 (NESHAPS [National Emission Standards for Hazardous Air Pollutants]) of the Clean Air Act."

Specifically the "top-down" approach shall include the following steps:

1. **Identify all available control technologies for a targeted pollutant:**
   The process begins by identifying the available control technologies and techniques on a source-by-source and pollutant-by-pollutant basis. All control options that have a practical potential for application are listed in this step. In order to identify the options, Lone Star has conducted a search of the EPA's RACT/BACT/LAER Clearinghouse (RBLC), other federal and state air permits and associated inspection/performance test reports, and controls applied to similar sources other than the source category being evaluated. Where applicable, references to a search of the RBLC have been included to illustrate control technologies implemented on similar sources. The RBLC is maintained by EPA and was created to assist applicants in selecting appropriate control technology for new and modified sources. The RBLC was accessed in a query of BACT using process type and pollutant and looking back over the past ten years. Appendix D to this document contains the results of RBLC queries as well as other supporting documentation for these analyses.

   Evaluation of technical feasibility and the energy, economic or environmental impacts, or other costs, are performed in subsequent steps.

2. **Eliminate technically infeasible options:**
   In this step, identified control options are evaluated for technical feasibility using source-specific factors. Demonstration of technical infeasibility for a technology should show that technical difficulties, based on physical, chemical, and engineering principles, prevent the successful use of the control option on the subject emission unit, or that the technology has never been demonstrated to function effectively on an identical or similar emissions unit. If a technology has not been demonstrated, then a careful review is conducted to determine if the technology is both "available" and "applicable."

3. **Rank remaining control technologies:**
   The overall control effectiveness of each remaining control technology is characterized for the pollutant under review. The effectiveness evaluation includes a review of the expected emission rates and expected emission reductions. The control option with the highest effectiveness is the "top" control option. If the top control option is proposed by the permit applicant as BACT, no further evaluation is required. Otherwise, the process moves to Step 4.

4. **Evaluate the most effective control and document results:**
   In this step, if any technically feasible control options are more effective than the proposed BACT option, the more effective options are compared and evaluated against the proposed BACT option. Factors considered in this evaluation include energy, environmental, and economic impacts, as well as other costs of the control options. The evaluation addresses both positive and negative impacts of each control option. An explanation for rejecting any control option that is more effective than the option ultimately selected as BACT is provided.

5. **Select BACT:**
   The most effective remaining control technology is proposed as BACT.

4.3 GHG BACT

This section presents Lone Star's demonstration that the FRAC III Project will utilize BACT for GHG.

4.3.1 Relevant Background

The BACT determination, as required, includes the overall energy efficiency through technologies practices and policies of each source type associated with the FRAC III Plant. In general, a more energy efficient technology burns less fuel. Energy efficient technologies in the BACT analysis help reduce the production of GHG and other regulated air pollutants. Because the FRAC III Plant involves the installation of new equipment, all of the equipment should be of the best engineering design and equipped with the latest technology to ensure energy efficiency.

When performing a "top-down" BACT analysis, an applicant is required to review control technologies for similar sources. These sources have been identified as the most similar and available to those associated with the Project.

The only control methods identified for control of GHG (including CO_2, N_2O and CH_4) are to limit GHG production using good combustion practices and to implement carbon capture and storage (CCS). Because there is very limited data available on GHG controls due to the newness of the program, Lone Star ran a search for GHG from all emissions sources found in the RBLC in an effort to identify all available control methods.

The best way to control combustion-related GHG and other regulated pollutants is through thermal efficiency achieved through design and operation. Good combustion practices are considered BACT for all the combustion sources and pollutants associated with the FRAC III Plant.

These practices are based on EPA guidance located at http://www.epa.gov/ttnatw01/iccr/dirss/gcp.pdf (included in Appendix D to this document) and are summarized in Table 4-2. This table serves as the BACT discussion for all combustion sources proposed with the Project. Lone Star will apply all of these practices and standards to each combustion source associated with the Project, unless otherwise noted.

4.3.2 GHG Emissions Source Categories

The majority (nearly 75%) of the contribution of GHG associated with the FRAC III Plant will be from the fuel gas-fired combustion sources (i.e., heaters, flare, and thermal oxidizer). The amine unit regenerator vent CO_2 constitutes the second largest contributor, and the piping component leaks (i.e., fugitive emissions) and diesel-fired engines will contribute a minor amount of GHG. Stationary combustion sources primarily emit CO_2, and a small amount of N_2O and CH_4.

This GHG BACT discussion is divided into two categories: stack GHG (including process-related and combustion-related GHG) and fugitive GHG.

4.3.2.1 Stack GHG

The Stack GHG sources emit the vast majority of the Site's GHG. Of the Stack GHG, the majority (over 70%) of the GHG will be emitted from the operation of the two process heaters, which will each operate up to 8,760 hr/yr, including provision for start-ups and shutdowns. A large portion of the Stack GHG will be emitted from the thermal oxidizer, which will operate up to 8,760 hr/yr. The heaters will be fired on fuel gas, while the thermal oxidizer will be fired on fuel gas as well as waste gas. The stack GHG emissions include process-related GHG (i.e., due to CO_2 and methane in the process and waste streams) and combustion-related GHG (i.e., due to the combustion of fuel gas and waste gas streams).

To identify control technologies and control levels for GHG from heaters and thermal oxidizers, Lone Star searched the RBLC, proposed 40 CFR Part 60 Subpart TTTT, recently issued permits and permitting guidance from other states, as well as recently submitted permit applications in Texas and other states. A copy of the RBLC download is included in Appendix D to this document.

TABLE 4-2

SUMMARY OF GOOD COMBUSTION PRACTICES

GHG PSD AIR PERMIT APPLICATION TO EPA

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

Good Combustion Technique	Practice	Standard
Operator practices	Official documented operating procedures, updated as required for equipment or practice change	Maintain written site specific operating procedures in accordance with Good Combustion Practices (GCPs), including startup, shutdown, and malfunction
	Procedures include startup, shutdown, malfunction	
	Operating logs/record keeping	
Maintenance knowledge	Training on applicable equipment and procedures	Equipment maintained by personnel with training specific to equipment
Maintenance practices	Official documented maintenance procedures, updated as required for equipment or practice change	Maintain site specific procedures for best/optimum maintenance practices
	Routinely scheduled evaluation, inspection, overhaul as appropriate for equipment involved	Scheduled periodic evaluation, inspection, overhaul as appropriate
	Follow vendor recommendation	
	Maintenance logs/record keeping	
Fuel quality (analysis); Use of clean fuels (natural gas)	Monitor fuel quality	Fuel analysis where composition could vary and where of significance to sulfur content
	Periodic fuel sampling and analysis	
	Lone Star shall use either pipeline quality natural gas or ethane product. These fuels burn more cleanly than fuels with higher hydrocarbon content.	
Combustion air distribution	Adjustment of air distribution system based on visual observations	Routine and periodic adjustments and checks
	Adjustment of air distribution based on continuous or periodic monitoring	
Good engineering design	Since the plant is a new construction, all sources shall be operating at the best efficiency possible by design.	Keep record of manufacturer’s certificate and maintain the engines as per the manufacturer’s guidelines.
Conducting visible emissions observations	Visible emissions observations shall be made and recorded in accordance with the requirements specified in 40 CFR §64.7(c).	Maintain schedule and records of the visible emission observation made.

Process-Related Stack GHG

The amine unit will emit process-related stack GHG. As discussed previously, the amine units' primary function is to remove CO_2 from the NGL. As part of the process, a small amount of hydrocarbons (including methane) can become entrained in the amine.

The amine unit flash tank vent stream, which is recycled back to the plant inlet, and the amine unit regenerator vent stream, which is vented to the thermal oxidizer, contain CO_2 and methane, which are process-related GHG emissions.

Maintenance, startup, and shutdown activities emit GHG due to CO_2 and methane contained in the process streams.

Combustion-Related Stack GHG

The FRAC III Plant will utilize electric-driven compressors and pumps, such that potential combustion-related emissions are eliminated (i.e., 100% control) from these sources.

The heaters at the FRAC III Plant will be fired on fuel gas (pipeline-quality natural gas and/or ethane product). The hot oil heater (FIN: 3HR15.001) will be rated at 215 MMBtu/hr and the mole sieve regenerator heater (FIN: 3HR15.002) will be rated at 59 MMBtu/hr. Both heaters will be equipped with NGULNB, or manufacturer equivalent, and will be controlled further with a common SCR system. Additionally, both heaters will be equipped with efficient heater and burner designs, and periodically tuned for thermal efficiency.

As stated previously, emissions from the amine unit regenerator vent will be routed to a thermal oxidizer for control of H_2S and VOC in the exhaust streams. The process-related CO_2 emissions from the amine unit will flow through the thermal oxidizer to atmosphere, and the hydrocarbon emissions, including methane, will be oxidized to form combustion-related GHG. The oxidizer will have a 99.9% DRE for hydrocarbon compounds, so 0.01% of the methane will pass through the oxidizer uncombusted, as process-related GHG. In addition, the oxidizer will fire fuel gas (i.e., generating combustion-related GHG), at maximum rate of 5 MMBtu/hr, as needed to maintain a combustion chamber temperature of 1,400 °F.

An intermittent Plant Flare will be utilized to control emissions associated with MSS activities, generating combustion-related GHG. The Plant Flare will have a 99% DRE for methane, so 1% of the methane in the MSS waste stream will pass through the flare as process-related GHG.

Please note the flare is not a continuous process flare, but an intermittent use MSS flare. Therefore, no continuous stream other than pilot and purge gas is being combusted, which are already authorized under previous permit actions.

The GHG emissions from combustion sources can be reduced by operating with thermal efficiency/good combustion practices. The Stack GHG emissions are able to be captured, so Carbon Capture and Storage (CCS) is an option for consideration. CCS is an emerging "end of the pipe" add-on control technology comprised of three stages (capture/compression, transport, and storage).

4.3.2.2 Fugitives

A small amount of GHG may be emitted via piping equipment leaks (i.e., due to CO_2 and methane in the process streams). It is infeasible to capture GHG emissions from fugitive sources such as piping leaks. Therefore, CCS is not an add-on control technology that has a potential for application and it is not identified as a feasible technology for controlling fugitives. However, fugitive GHG emissions can be reduced by utilizing a LDAR program. There are many structured LDAR programs that have been developed as part of state and federal rulemaking and BACT. Lone Star has evaluated the existing programs for the purpose of this BACT analysis.

4.3.3 Stack GHG BACT

The only control methods identified for control of GHG (including CO_2, N_2O, and CH_4) from fuel gas combustion are to limit GHG production using good combustion practices and periodically tune equipment and to implement carbon capture and storage (CCS). The best way to control combustion-related GHG and other regulated pollutants is through thermal efficiency achieved through design and operation. Good combustion practices are considered part of the proposed BACT for all the combustion sources and pollutants associated with the FRAC III Project.

The following paragraphs present Lone Star's evaluation of BACT for the remaining stack GHG emissions.

4.3.3.1 Step 1 | Identify All Available Control Technologies

Lone Star has identified the following potentially applicable control technologies for controlling process-related and combustion-related stack GHG emissions associated with the Project:

<u>All Stack GHG</u>

- Carbon Capture and Transport and/or Storage (CCS) as add-on control.

<u>Process-Related Stack GHG Only</u>

Because the amine unit will be designed to remove CO_2 from the NGL, the generation of CO_2 (GHG) is inherent to the process, and a reduction of CO_2 emissions by process changes would only be achieved by a reduction in the process efficiency. The amine unit will emit methane (GHG) at the point of amine regeneration, due to a small amount of NGL becoming entrained in the rich amine.

MSS activities emit GHG due to CO_2 and methane contained in the process streams.

The methods to reduce process-related stack GHG include:

- Proper Design and Operation: The amine unit will be designed to include a flash tank, in which gases (including CO_2 and methane) will be removed from the rich amine or rich glycol stream prior to regeneration, thereby reducing the amount of waste gas created. Lone Star will construct and operate the amine unit for optimal performance;
- Routing amine unit flash tank offgas to the FRAC III Plant inlet: This control method will reduce the methane and CO_2 emissions by 100%;
- Routing amine unit flash tank offgas and/or amine regenerator vent to a thermal oxidizer: This control device will reduce the methane emissions by 99.9% and will convert those emissions to CO_2, which has a lower GWP. This control device will also generate CO_2 from combustion of other hydrocarbons in the waste gas stream;
- Routing amine unit flash tank offgas and/or amine regenerator vent to a flare: This control device will reduce the methane emissions by 99% and will convert those emissions to CO_2, which has a lower GWP. This control device will also generate CO_2 from combustion of other hydrocarbons in the waste gas stream;
- Minimize duration of MSS activities: minimize outage time of the Deethanizer and coordinate inlet filter change outs, pump/compressor maintenance, and meter recalibration;
- Routing MSS emissions to a thermal oxidizer: This control device will reduce the methane emissions by 99.9% and will convert those emissions to CO_2, which has a lower GWP; and
- Routing MSS emissions to a flare: This control device will reduce the methane emissions by 99% and will convert those emissions to CO_2, which has a lower GWP.

<u>Combustion-Related Stack GHG Only</u>

The methods to reduce combustion-related stack GHG include:

- Fuel selection/switching: Non-emergency equipment will be firing only pipeline quality natural gas and/or ethane product, which results in 28% less CO_2 production than fuel oils (see 40 CFR Part 98, Subpart C, Table C-1, which is included in Appendix E, for a comparison of the GHG emitting potential of various fuel types);
- Good Combustion Practices: Techniques include operator practices, maintenance knowledge, and maintenance practices;
- Use of electric-driven engines and pumps, where technically feasible: The compressors and pumps will be electric-driven, resulting in no GHG emissions from these sources;
- Efficient heater and burner design: New burner design improves the mixing of fuel, creating a more efficient heat transfer. Because this is a new facility, new burners will be utilized;
- Burner management systems: The heaters will be equipped with burner management systems, that will include intelligent flame ignition, flame intensity controls, and flue gas recirculation;
- Periodic tune-ups and maintenance for optimal thermal efficiency: Periodic tune-ups will increase the efficiency of the equipment. Maintenance will be performed routinely per vendor recommendations or the facility's maintenance plan, and replacing or servicing components will

be performed as needed. Lone Star will tune the heaters once a year for optimal thermal efficiency;

- Fuel gas pre-heating: Preheating the fuel stream reduces the heating load, increases thermal efficiency and therefore reduces emissions.   Lone Star will not be preheating the fuel gas for the heaters because more efficient options are available, as described below in Step 4;
- Oxygen trim control: Combustion devices operate with a certain amount of excess air to reduce emissions and for safety consideration. An inappropriate mixture may lead to inefficient combustion. Regular maintenance of the draft air intake systems of the heaters can reduce energy usage. Draft control is applicable to new or existing process heaters and is cost effective for process heaters rated at 20 to 30 MMBtu/hr or greater. The heaters will have air and fuel valves mechanically linked to maintain the proper air to fuel ratio;
- Air to fuel ratio controllers: Oxygen monitors and intake flow monitors can be used to optimize the fuel/air mixture and limit excess air and reduce the amount of energy required to heat the stream and, therefore, reduce the CO_2e emissions. As stated previously, the heaters' air and fuel valves will be mechanically linked to maintain the proper air to fuel ratio;
- Heat Recovery: The hot effluent from the hot oil heater will be cooled in the primary and secondary heat exchangers that heat the hot oil (heat transfer medium for the FRAC III Plant) to recover this energy and reduce the overall energy use in the plants. Tertiary exchangers will also recover heat and contribute to overall energy efficiency. Finally, the combustion convective section will be used to pre-heat the hot oil to the extent that the final exiting flue gas temperature is reduced to its practical limit;
- Energy efficiency: High efficiency motors and variable speed drives reduce electricity consumption by 4 – 17% when compared to standard motors and fixed speed drives;
- Proper heater operation: Proper operation involves providing the proper air to fuel ratio, residence time, temperature, and combustion zone turbulence essential to maintain low emissions;
- Proper flare operation: Poor flare combustion efficiencies lead to higher methane emissions and higher overall GHG emissions. Poor combustion efficiencies can occur at very low flare rates, very high flowrates (i.e., high flare exit velocities), and when flaring gas with low heat content and excessive steam to gas mass flows. Lone Star will only be flaring high Btu gases, will monitor the Btu content on the flared gas, and will have air assisted combustion allowing for improved flare gas combustion control and minimizing periods of poor combustion. Please note the flare is not a process flare, but an intermittent use MSS flare. Therefore, no continuous stream (other than pilot gas) is being combusted, and add on controls are not technically feasible.   Periodic maintenance will help maintain the efficiency of the Flare. The Flare will also be operated in accordance with 40 CFR §60.18, including heating value and exit velocity requirements, as well as pilot flame monitoring;
- Proper thermal oxidizer operation: Periodic maintenance will help maintain the efficiency of the thermal oxidizer. Temperature monitoring will ensure proper thermal oxidizer operation.
- Limiting operation of liquid fuel-driven engines: The emergency diesel generators and firewater pump will be limited to 36 hours of non-emergency operation per year; and
- Limit of start-up operations to 1 hour for the heaters.

4.3.3.2 Step 2 | Eliminate Technically Infeasible Options

Lone Star considers all identified options listed in Section 4.3.3.1 to be technically feasible, except for the following option:

Routing MSS Emissions to a Thermal Oxidizer: Not Feasible

A thermal oxidizer is not considered a technically feasible control device for the control of intermittent MSS events, as there are a very wide range of flow rates. The oxidizer would have to be designed for maximum MSS flow rates, and it would have to combust fuel gas (i.e., generating additional combustion-related emissions, including GHG) during the majority of the time when MSS emissions are not occurring at the maximum flow rate. A flare is the only technically feasible option for control of an intermittent stream of varying flow.

4.3.3.3 STEP 3 | Rank Remaining Control Technologies

Because thermal efficiencies are work practice standards, it is difficult to identify discriminate control efficiencies for ranking. Lone Star used *Available and Emerging Technology for Reducing Greenhouse Gas Emission from the Petroleum Industry* dated October 2010 and *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Manager*, Document Number LBNL-964E, dated June 2008, to identify any available control efficiencies. The efficiency improvement/GHG reduction technologies are ranked below. The technologies that Lone Star will be implementing are in bold-face type.

- **Use of electric-driven engines (100%);**
- **Routing the amine unit flash tank back into the FRAC III Plant inlet (100%);**
- **Routing the amine unit regenerator vent to a thermal oxidizer (99.9% for methane, generates CO_2);**
- **Limiting operation of liquid fuel-driven engine (>99% compared with continuous operation);**
- Routing the amine unit waste gas vents to a flare (99% for methane, generates CO_2);
- **Routing MSS event emissions to a flare (99% for methane, generates CO_2);**
- **Fuel selection/switching (28% when comparing fuel gas and No. 2 Fuel Oil);**
- **Efficient burner and heater design - burner management systems with intelligent flame ignition, flame intensity controls, and flue gas recirculation (10-25%);**
- **Energy efficiency (4-17% of electricity consumption) using high efficiency motors, variable speed drives;**
- Preheating fuel stream (10-15%);
- **Proper heater, flare and thermal oxidizer operation (1-15%);**
- **Annual tune-ups and maintenance (1-10%);**
- **Heat recovery on heaters (2-4%);**
- **Combustion air controls – limitations on excess air (1-3%);**

- **Minimize duration of MSS activities;**
- **Limit of start-up operation to 1 hour for heaters; and**
- CCS (not a feasible option for the Project due to technical, environmental, and economic reasons, as discussed in Step 4).

Table 4-3 lists these technologies and the source of the estimated GHG control efficiencies.

4.3.3.4 STEP 4 | Evaluate the Remaining Control Efficiencies

Lone Star is implementing the top ranked BACT for Stack GHG. Of the technologies listed in Step 3, only three options are not proposed to be implemented as part of the Project. First, Lone Star will not be routing the amine unit regenerator vent to a flare (99% control), because a more efficient technology (thermal oxidizer, with 99.9% efficiency) is being used. Second, Lone Star will not be preheating the fuel, because the burner management systems, which include flue gas recirculation, achieve a higher overall combustion efficiency. Finally, CCS is not considered by Lone Star to be feasible, based upon its lack of readily available technologies and negative environmental impacts, as well as its negative economic impacts. However, per EPA guidance, EPA has identified CCS as an add-on control technology that is available for the Stack GHG that must be evaluated as if it were technically feasible.

The emerging CCS technology is an "end of pipe" add-on control method comprised of three stages (capture/compression, transport, and storage). CCS involves separation and capture of CO_2 from the exhaust gas, pressurization of the captured CO_2, transmission of CO_2 via pipeline, and injection and long term geologic storage of the captured CO_2. Several different technologies are at varying stages of development, some at the slip stream or pilot scale while many others are still at the bench top or laboratory stage of development.

The use of CCS on the Stack GHG emissions is not technically or environmentally feasible for the FRAC III Plant. The goal of CO_2 capture is to concentrate the CO_2 stream from an emitting source for transport and injection at a storage site. CCS requires a highly concentrated, pure CO_2 stream for practical, economic, and pipeline safety reasons. The flare is an intermittent MSS flare; no continuous stream (other than pilot gas) is combusted, and no add-on equipment is technically feasible for the flare. Therefore, CCS is considered technically infeasible for the flare.

For continuously operated equipment, extracting CO_2 from exhaust gases requires equipment to capture the flue gas exhaust and to separate and pressurize the CO_2 for transportation. The stack vent streams will be low pressure, high volume streams at a very high temperature, with low CO_2 content and will contain miscellaneous pollutants, such as PM that can contaminate the separation process. Table 4-4 summarizes the stack parameters and CO_2 content of the streams.

TABLE 4-3

GHG CONTROL TECHNOLOGY RANKING FOR BACT STEP 3

GHG PSD AIR PERMIT APPLICATION TO EPA

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

Control Technology	Estimated GHG Percent Reduction	Source of Percent Reduction Determination	Proposed as BACT?
Electric-driven engines	100	Based upon only using electricity so no combusted related GHG emissions	Yes
Amine unit flash tank offgas recovery system	100	Hard piped back into the fuel or inlet system	Yes
Amine unit regenerator vent to thermal oxidizer	99.9	Vendor Data	Yes
Limiting operation of fuel-driven engines	>99	36 / 8,780 potential operating hours	Yes
Amine unit regenerator vent to flare	98	http://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/flares/	No
Routing MSS event emissions to a flare	98	http://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/flares/	Yes
Fuel selection/switching (natural gas versus No. 2 Fuel Oil)	28	40 CFR Part 98 Subpart C, Table C-1	Yes
Burner management systems	10-25	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y issued by EPA October 2010 Section 5.1.2.1 Draft Control and Vendor Data	Yes
High efficiency motors	4-17	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y 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	Yes
Preheating fuel stream	10-15	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y issued by EPA October 2010 Section 5.1.2.2 Air Preheating and Table 1 Summary of GHG Reduction Measures for the Petroleum Refinery Industry	No
Proper heater, flare and thermal oxidizer operation	1-15	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y 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	Yes
Annual tune-ups and maintenance	1-10	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y issued by EPA October 2010 Section 5.1.1.5 Improved Maintenance	Yes
Heat recovery on heaters	2-4	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y 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	Yes
Combustion air controls	1-3	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y 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	Yes
Minimize duration of MSS activities	N/A	N/A	Yes
Limit start up operation to 1 hour for heaters	N/A	N/A	Yes
CCS	80	*Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr* y issued by EPA October 2010 Section 5.1.4 Carbon Capture. Also noted that industrial application of this technology is not expected to be available for 10 years.	No

TABLE 4-4

STACK GHG EXHAUST PARAMETERS AND CO_2 CONTENT

GHG PSD AIR PERMIT APPLICATION TO EPA

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

Combustion Source EPN	CO_2[a] (T/yr)	CO_2[b] (MMscf/yr)	Stack Diameter[c] (ft)	Exit Velocity[c] (fps)	Temp.[c] (°F)	Total Exhaust[d] (MMscf/yr)	Percent CO_2[e] (vol%)
3GEN.001	14.96	0.26	0.67	150.33	950	2,000	0.01%
3GEN.002	16.73	0.29	0.67	150.33	950	2,000	0.01%
3PM18.044	14.96	0.26	0.67	150.33	950	626	0.04%
3HR15.001	129,302.87	2,262.80	7.6	42.3	555	31,470	7.19%
3HR15.001	742.27	12.99	7.6	42.3	555	31,470	0.04%
3HR15.002	35,483.11	620.95	7.6	42.3	555	31,470	1.97%
3HR15.002	203.69	3.56	7.6	42.3	555	31,470	0.01%
3SK25.002	51,341.08	898.47	4.5	109.0	1,400	15,512	5.79%
1SK25.001 (Waste Gas)	396.21	6.93	2.5	101.3	800	6,569	0.11%
Totals/Average:	**217,515.88**	**3,807**			**663**	**152,588**	**2.49%**

[a] Please see Appendix B for the calculation of CO_2 emissions from these sources.

[b] The CO_2 volumetric flow rate is calculated as follows (example is for 3GEN.001):

(14.96 T/yr CO2) * (2,000 lb/T) / (44 lb/lb-mole CO2) * (385 scf/lb-mole) / (10^6/MM) = 0.26 MMscf/yr CO2

[c] This value was taken from the Table1(a), which is located in Appendix A.

[d] The Total Exhaust volumetric flow rate is calculated as follows (example is for 3GEN.001):

(150.33 fps) * (3,600 s/hr) * (PI * (0.7/2 ft)^2) * (459.67+68 °F) / (459.67+950 °F) * (8,760 hr/yr) / (10^6/MM) = 1,999.82 MMscf/yr

[e] Percent CO_2 is calculated as follows (example is for 3GEN.001):

(0.26 MMscf/yr CO2) / (1,999.82 MMscf/yr exhaust) * (100%) = 0.01%

At the 6th Pipeline Technology Conference in 2011, C.M.Spinelli (eni.) presented "Technical challenges facing the transport of anthropogenic CO_2 by pipeline for carbon capture and storage purposes," by G. Demofonti (Centro Sviluppo Materiali) and C.M. Spinelli (eni.). In that report, Spinelli discusses current issues related to CO_2 transport:

> *The natural gas industry has extensive experience on pipeline transportation. However, CO_2 (and in particular anthropogenic CO_2) shows significantly different physical properties and behaviour in the pipeline transportation process. Compared to natural gas, the most relevant differences regarding structural integrity issues are:*
>
> - *Higher susceptibility to long-running ductile fracture propagation than natural gas pipeline operating at comparable material usage working conditions, as the CO_2 decompression curve is more severe and as a consequence the driving force is stronger and the crack arrest conditions can be reached only using steel pipes with very high toughness, or using external mechanical devices (Crack Arrestors) and/or using innovative ultra high "equivalent toughness" reinforced pipes. …*
> - *The high likelihood to have lower temperatures during service operation (as during line venting down to -20°C) or in case of a unlikely event of a leakage (down to T = -80°C) due to the significant Joule Thomson cooling effect (as indicated by H. Mahgerefteh,…) which results in pipe material toughness decreasing.*
> - *Increased pipe wall corrosion and/or stress corrosion susceptibility when free water phase is present within the CO_2 mixture.*
>
> *Regarding the first point, it is worth noting that the decompression behaviour of CO_2 leads to more severe crack propagation driving force compared to natural gas; this has been known since the first studies carried out by Battelle 30 years ago…and has recently confirmed by the desk studies of Cosham, and Eiber…. These tests and studies highlight the key role of impurities in the anthropogenic CO_2 mixture, and their detrimental effect on crack propagation driving force….*

Therefore, CO_2 separation is a vital first step for CCS. The CO_2 separation would first require the removal of PM from the streams without creating too much back pressure on the upstream system (i.e., the Plant's combustion processes). Next, it would require inlet compression to increase the pressure from atmospheric to the minimum of 700 pounds per square inch (psi) required for efficient CO_2 separation. The installation of cryogenic units or other cooling mechanisms (e.g., complex heat exchangers) would be required to reduce the temperature of the streams from over 500 °F to less than 100 °F prior to separation, compression, and transmission. The cryogenic units would each require propane compression, which could be gas-fired (i.e., generating additional GHG emissions) or electric driven.

Also, the installation of an additional dedicated amine unit to capture the CO_2 from the exhaust/waste streams and a gas-fired heater to separate CO_2 from the rich amine would be required. Finally, the separated CO_2 stream would require large compression equipment to pressurize the CO_2 to transfer to the Denbury pipeline. The CO_2 compressors must be designed to handle acidic gases, with high energy consumption/cost to pressurize the CO_2 from near atmospheric pressure up to the receiving pipeline pressure to transfer offsite.

The combined volumetric flow of the Stack GHG is 152,588 MMscf/yr, and the CO_2 content of the combined Stack GHG exhaust stream is 2.2 mol%. To process this stream for CCS, the FRAC III Plant would need to have additional amine units, cryogenic units, dehydration units, and associated equipment (i.e., heaters, tanks, compressor engines, and piping).

If the compression were to be gas-fired, Lone Star estimates that six (6) Caterpillar 3616 engines would be needed for inlet compression and six (6) Caterpillar 3616 engines would be needed for CO_2 compression. Alternatively, electric engines for a total of over 15,000 hp output would be required, significantly increasing the electrical load of the Frac III Plant.

Considering the additional equipment and associated emission sources, implementing CCS at the Site could generate additional GHG more than twice the major source threshold (100,000 T/yr) and additional VOC emissions greater than the respective NNSR significance threshold (25 T/yr). An estimate of the emissions from the compressor engines is included in Appendix D, and the totals are:

- CO: 21.97 T/yr
- NO_X: 9.64 T/yr
- $PM_{10}/PM_{2.5}$: 4.61 T/yr
- SO_2: 0.34 T/yr
- VOC: 35.71 T/yr
- GHG: 215,935.64 T/yr

Therefore, Lone Star believes that CCS is not BACT due to its negative environmental and energy impacts.

There are several on-going CCS projects, ranging in cost from $300 million to $2.6 billion that are heavily funded by the US Department of Energy (DOE) and the Canadian Government. These projects are mostly at coal fired utilities and are small in scale (i.e., only involving a slip stream or are still in the laboratory stage of development). Note that slip stream processing does not enable the evaluation of back pressure studies.

According to the guidance documents for GHG permitting and for reducing carbon dioxide emissions from bioenergy, EPA has concluded that although CCS is available it does not necessarily mean it would be selected as BACT due to its technical and economic infeasibility. In addition, EPA supports the conclusion of the Interagency Task Force on Carbon Capture that although current technologies could be used to capture CO_2 from new and existing plants, they are not ready for widespread implementation.

This conclusion is primarily because the technologies have not been demonstrated at the scale necessary to establish confidence in their operations.

Based upon on the issues identified above, Lone Star does not consider CCS to be a technically, economically, or commercially viable control option for the FRAC III Plant's stack GHG.

Finally, assuming that CCS were readily available and could be implemented on a large-scale basis without negative environmental impact, Lone Star would still have to resolve several logistical issues including obtaining right of way (ROW) for the pipeline and finding a storage facility or other operation that would be available to receive and handle a large volume of CO_2.

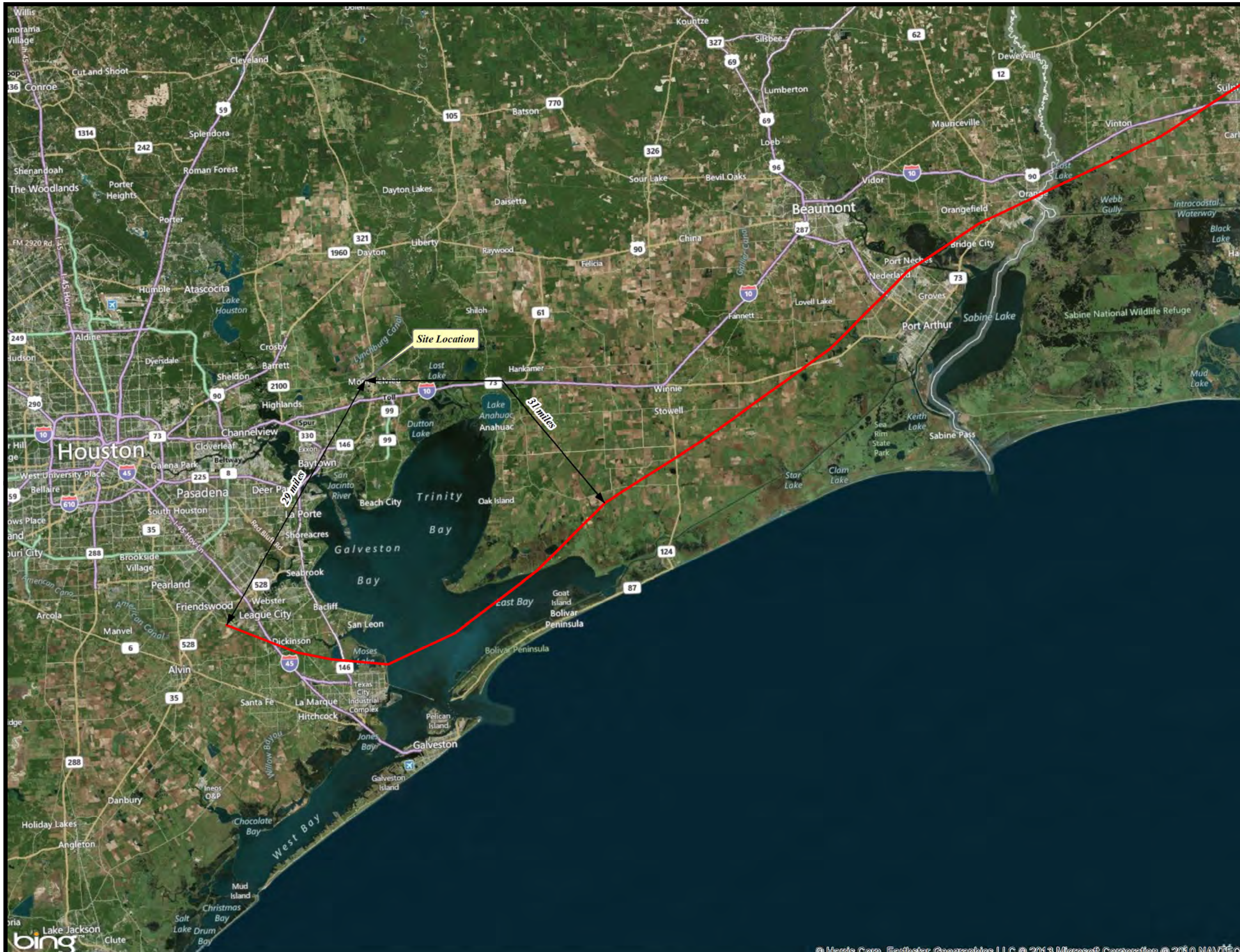
Figure 4-1 shows the locations of the CO_2 pipelines nearest the Plant, based upon a review of readily available public information obtained via Internet search. The nearest identified pipeline that transports CO_2 is approximately 35 miles from the FRAC III Plant. For the purpose of this BACT analysis, Lone Star has assumed that the Denbury pipeline is the nearest available CO_2 pipeline.

The National Energy Technology Laboratory (NETL) is part of DOE's national laboratory system and is owned and operated by DOE. NETL supports DOE's mission to advance the national, economic, and energy security of the United States. Lone Star utilized the March 2010 NETL Document *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447* to estimate the cost associated with the pipeline and associated equipment. This document provides a best estimate of transport storage and monitoring costs for a "typical" sequestration project.

CO_2 transport costs are broken down into three categories, as follows:

- **Pipeline/Transfer Costs -** Pipeline costs are derived from the Oil and Gas Journal's annual Pipeline Economics Report for natural gas, oil, and petroleum projects which are expected to be analogous of the cost of building a CO_2 pipeline. The cost estimate includes pipeline materials, direct labor, indirect costs, and right of way acquisition as a function pipeline length and diameter and is based upon a study completed by the University of California.
- **Related Capital Expenditures** – Capital costs associated with CCS are estimated based upon the DOE/NETL study, *Carbon Dioxide Sequestration in Saline Formation* – Engineering and Economic Assessment for typical costs associated with pipeline. The costs were adjusted to include a CO_2 surge tank and pipeline control system. Miscellaneous costs also include surveying, engineering, supervision, contingencies, allowance, overhead, and filing fees.
- **O&M Costs** – O&M costs are based on the DOE/NETL report *Economic Evaluation of CO_2 Storage and Sink Enhancement Option* on a cost/pipeline length basis.

To estimate costs for the FRAC III Plant, Lone Star utilized the following parameters and the March 2010 NETL document *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs* DOE/NETL-2010/144.



Legend

Denbury Pipeline

N
W E
S

0 10 20
Miles

TITAN Engineering, Inc.
2801 Network Boulevard, Suite 200
Frisco, Texas 75034
Phone: (469) 365-1100 Fax: (469) 365-1199
www.titanengineering.com ; www.apexcos.com
A Division of Apex Companies, LLC

Lone Star NGL

FIGURE 4-1 CO_2 PIPELINE MAP

Lone Star NGL Fractionators LLC
Mont Belvieu Gas Plant
FRAC III Project
GHG PSD Air Permit Application
TITAN Project No. 84800475-08.001
June 2013

Digital Data Courtesy of ESRI Online Datasets

Because the cost of transport and storage of the Stack GHG emissions would be higher than the cost of just transport, Lone Star is conservatively (i.e., estimating costs on the low side) assuming that the Denbury pipeline would be a viable recipient of the CO_2 emissions and, therefore, addressing the transportation costs only. Assuming that the Denbury pipeline would be able to receive the CO_2 stream, the estimated cost associated with transport of the FRAC III Plant CO_2 to the Denbury pipeline is over $18 million. Table 4-5 presents a conservative (i.e., tending to underestimate the cost) cost determination. The cost estimate does not include certain costs that would be required, as described in the following paragraphs.

It should be noted that liability costs are not included in this cost estimate. Liability protections address the fact that if damages are caused by transportation of CO_2, the transporting party may bear a financial liability. Several types of liability are available (Bonding, Insurance, etc.). The liability regime has yet to be established on a state or federal level. However, some states (Wyoming, North Dakota, and Louisiana) have established trust funds ($5 MM) and liability timeframes (on average 10 years).

A conservative cost estimate indicates that the cost of CCS is approximately over 50% of the cost of the FRAC III Plant. Therefore, Lone Star considers this option to be economically unreasonable.

In summary, Lone Star believes that CCS is not BACT due to technical, environmental, and economic reasons.

4.3.3.5 STEP 5 | Select BACT

As shown previously, Lone Star is implementing the following technologies that together meet BACT for Stack GHG emissions:

- Use of electric-driven engines (100%);
- Routing the amine unit flash tank back into the plant processes (100%);
- Routing the amine unit regenerator vent to a thermal oxidizer (99.9% for methane, generates CO_2);
- Limiting operation of fuel-driven engine (>99% compared with continuous operation);
- Routing MSS event emissions to a flare (99% for methane, generates CO_2);
- Fuel selection/switching (28% when comparing fuel gas and No. 2 Fuel Oil);
- Efficient burner and heater design - burner management systems with intelligent flame ignition, flame intensity controls, and flue gas recirculation (10-25%);
- Energy efficiency (4-17% of electricity consumption) using high efficiency motors and variable speed drives;
- Proper heater, flare and thermal oxidizer operation (1-15%);
- Annual tune-ups and maintenance (1-10%);
- Heat recovery on heaters (2-4%);
- Combustion air controls – limitations on excess air (1-3%);
- Minimize duration of MSS activities; and
- Limit of start-up operation to 1 hour for heaters.

TABLE 4-5

ESTIMATED COSTS FOR CCS OF STACK CO_2 EMISSIONS

GHG PSDAIR PERMIT APPLICATION TO EPA

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

CO_2 Pipeline Data

Pipeline Length (L)[1]	29	miles
Pipeline Diameter (D)[2]	8	inches
Number of Injection Wells	0	
Depth of well	N/A	feet
	N/A	meters

CCS Cost Breakdown

Cost Type	Units	Cost		
Pipeline Costs[3]				
Pipeline Materials	$ Diameter (inches), Length (miles)	$64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D + 26,920)	$	2,940,572.44
Pipeline Labor	$ Diameter (inches), Length (miles)	$341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)	$	11,531,396.77
Pipeline Miscellaneous	$ Diameter (inches), Length (miles)	$150,166 + $1.58 x L x (8,417 x D + 7,234)	$	3,566,963.40
Pipeline Right of Way	$ Diameter (inches), Length (miles)	$48,037 + $1.20 x L x (577 x D +29,788)	$	1,245,296.20
Other Capital				
Refrigeration Compressions (2 CAT 3516)	$	$18,000,000	$	18,000,000.00
Inlet/Residue Compressions (3 CAT 3616)	$	$74,400,000	$	74,400,000.00
CO_2 Compression Equipment	$	$2,000,000	$	2,000,000.00
Cryogenic Units/Amine Units /Dehydration	$	$666,667	$	666,666.67
CO_2 Surge Tank	$	$1,150,636	$	1,150,636.00
Pipeline Control System	$	$110,632	$	110,632.00
O&M[2]				
Fixed O&M	$/mile/year	$8,632	$	250,328.00
		Total Pipeline Cost	**$**	**115,862,491.48**

Amoritized CCS Cost

Total Capital Investment (TCI) =			**$**	**115,612,163.48**
Capital recovery factor (CRF) [1] = $i(1+i)^n/((1+i)^n - 1)$			$	0.15
i = interest rate =	0.08			
n = equipment life =	10	years		
		Amortized installation costs = CRF * TCI =		**$17,229,621.61**
		Total CCS Annualized Cost		**$17,479,949.61**

[1] Distance to pipeline is calculated based on approximate location of Denbury Green pipeline in Chambers County as shown on Figure 4-1.

[2] "Estimating Carbon Dioxide Transport and Storage Costs," National Energy Technology Laboratory, U.S. DOE, DOE/NETL - 2010/1447, March 2010

[3] Cost adjusted using average consumer price index to 2011 dollars from 2007 dollars based on data presented in Estimating Carbon Dioxide Transport and Storage Costs," National Energy Technology Laboratory, U.S. DOE, DOE/NETL - 2010/1447, March 2010.

NOTE: This cost estimate sheet does not include

Amoritized Project Cost (without CCS)

Total Capital Investment (TCI) =			**$**	**324,479,615.00**
Capital recovery factor (CRF) [1] = $i(1+i)^n/((1+i)^n - 1)$			$	0.10
i = interest rate =	0.08			
n = equipment life =	20	years		
		Amortized installation costs = CRF * TCI =		**$33,048,965.51**
		Total Project Annualized Cost		**$33,048,965.51**

NOTE: Plant lifetime estimated at 20 years, due to normal plant lifetime expectations. However, CCS equipment life anticipated to be 10 years based upon extreme acidic conditions of CO_2 stream.

4.3.4 Piping Fugitives GHG BACT

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 Plant's total GHG emissions. However, for completeness it is addressed in this BACT analysis.

Lone Star will be implementing the 28LAER LDAR program on the VOC and fuel gas streams at the FRAC III Plant 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.

The use of compressed air-driven pneumatic controllers instead of natural gas will lower methane emissions from the FRAC III Plant.

In summary, Lone Star believes that the use of low bleed and air driven pneumatic controllers, where practicable, and the implementation of the 28LAER LDAR program will reduce fugitive GHG emissions by 80-90%, thereby constituting BACT.

4.3.4.1 STEP 1 | Identify All Potential Control Technologies

The following control technologies for process fugitive emissions of CO_2e are listed below:

- Implementation of a LDAR program: 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. Organic vapor analyzers or cameras are commonly used in LDAR programs. TCEQ's 28LAER LDAR is currently the most stringent program, which can achieve efficiencies of 97% for valves. Lone Star will implement TCEQ's 28LAER program on all VOC lines and the fuel gas (high methane content) in the FRAC III Plant; this program will result in a reduction of GHG emissions from these piping components; and
- Use of low-bleed gas-driven pneumatic controllers or compressed air-driven pneumatic controllers: low-bleed gas-driven pneumatic controllers emit less gas (that contains GHG) than standard gas-driven controllers, and compressed air-driven pneumatic controllers do not emit GHG.

4.3.4.2 STEP 2 | Eliminate Technically Infeasible Option

All of the technologies listed in Step 1 are technically feasible.

4.3.4.3 STEP 3 | Rank Remaining Control Technologies

Lone Star intends to implement all technologies listed in Step 1, which together will reduce fugitive GHG emissions by 80-90%. Therefore, Lone Star is not ranking the technologies individually. For comparison purposes, the Table 4-6 presents the LDAR parameters for the proposed 28LAER program and other LDAR programs. As shown in the attached table, the LDAR proposed for the Project is the top BACT.

4.3.4.4 STEP 4 | Evaluate the Remaining Control Efficiencies

Because Lone Star intends to implement TCEQ's 28LAER LDAR program, which is the top-ranked technology, there is no need for evaluation under Step 4.

4.3.4.5 STEP 5 | Select BACT

Lone Star proposes that implementing TCEQ's 28LAER LDAR program for all components in VOC and fuel gas service and the use of low-bleed gas-driven pneumatic controllers or compressed air-driven pneumatic controllers where feasible constitutes BACT for fugitive GHG emissions.

TABLE 4-6

COMPARISON OF LDAR PROGRAMS

GHG PSD AIR PERMIT APPLICATION TO EPA

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

	Leak Definition (ppmv)								
Component Type	**TCEQ 28LAER (Proposed BACT)**	**TCEQ 28VHP**	**TCEQ 28M (VP>0.5 psi)**	**TCEQ 28RCT (VP>0.044 psi)**	**TCEQ 30TAC115[a]**	**NSPS KKK**	**MACT HON**	**NSPS GGG and VV**	**NSPS GGGa and VVa**
Valves-Gas	500	500	10,000	500	500	10,000	500	10,000	500
Valves-Light Liquid	500	500	10,000	500	500	10,000	500	10,000	500
Valves-Heavy Liquid	AVO Program[b]	AVO Program [b]	AVO Program	AVO Program	AVO Program	AVO Program	AVO Program	AVO Program	AVO Program
Pressure Relief Valve-Gas	500	500	10,000	500	500	10,000	500	500	500
Pressure Relief Valve-Liquid	500	500	10,000	500	500	10,000	AVO Program	AVO Program	AVO Program
Pumps-Light Liquid	500	2,000	10,000	10,000	10,000	AVO Program	2,000	10,000	2,000
Pumps-Heavy Liquid	AVO Program	AVO Program	AVO Program	AVO Program	AVO Program	AVO Program	AVO Program	AVO Program	AVO Program
Flanges/Connectors [c]	NA	NA	NA	NA	NA	AVO Program	500	AVO Program	500
VOC Compressors	500	2,000	10,000	10,000	10,000	Seal System	Seal System	Seal System	Seal System
Closed Vent Systems	500	500	10,000	500	500	500	500	500	500

[a] From 30 TAC Chapter 115, Subchapter D, Division 3: Fugitive Emission Control in Petroleum Refining, Natural Gas/Gasoline Processing, and Petrochemical Processes in Ozone Nonattainment Areas.

[b] AVO Program is a formal audio/visual/olfactory (AVO) program including stipulated periodic inspections, as-needed follow-up monitoring, and as-needed follow-up repairs, and documentation.

[c] Except as noted, requirement does not stipulate a monitoring program for flanges/connectors. However, flange/connector monitoring must be performed to use control efficiency in calculating potential and actual emissions. The add-on TCEQ monitoring program for flanges/connectors is 28CNTA.

5 REGULATORY APPLICABILITY

The following sections demonstrate that the Project emissions sources will meet the applicable federal and state air quality rules and regulations defined in 30 TAC §116.111(a)(2). Furthermore, the following sections also demonstrate that the FRAC III Plant will be operated in accordance with the intent of the Federal Clean Air Act and the Texas Clean Air Act, including protection of the health and physical property of the people.

5.1 Protection of Public Health and Welfare - §116.111 (a)(2)(A)

As outlined below, the proposed emissions from this project will comply with all TCEQ rules and regulations and with the intent of the Texas Clean Air Act.

5.1.1 30 TAC 101 - General Air Quality Rules

The FRAC III Plant will be operated in accordance with the General Rules relating to circumvention, nuisance, traffic hazard, notification requirements for major upset, notification requirements for maintenance, sampling, sampling ports, emissions inventory requirements, sampling procedures and terminology, compliance with Environmental Protection Agency Standards, the National Primary and Secondary Air Quality Standards, inspection fees, emissions fees, and all other applicable General Rules.

5.1.2 30 TAC 111 - Control of Air Pollution from Visible Emissions and Particulate Matter

The potential applicability of this chapter to sources in this application is explained in the following table. Brief explanations of compliance are provided for all applicable rules.

Section Number	Reference	Applicability	Compliance Explanation
§111.111-113	Visible Emissions	Yes	The single SCR stack for the heaters will have a flow greater than 100,000 acfm, and will meet the 15% opacity limit. The remaining stacks will have flow rates much lower than 100,000 acfm and will have less than 20% opacity.
§111.121-129	Solid Waste Incineration	No	Lone Star is not proposing solid waste incineration activities as part of this application.
§111.131-139	Abrasive Blasting of Water Storage Tanks Performed by Portable Operations	No	Abrasive blasting of water storage tanks is not being proposed as part of this permit application.

Section Number	Reference	Applicability	Compliance Explanation
§111.141-149	Materials Handling, Construction, Roads, Streets, Alleys and Parking Lots	No	The FRAC III Plant will be located in Chambers County, which is not within the geographic area of applicability.
§111.151	Allowable Emission Limits on Nonagricultural Processes	Yes	The FRAC III Plant's particulate emissions will be less than the allowable emission limits specified in §111.151.
§111.153	Emission Limits for Steam Generators	No	The Project will not include a steam generator, as defined in this section.
§111.171-175	Emission Limits on Agricultural Processes	No	Lone Star will not conduct agricultural processes as part of this application.
§111.181-183	Exemptions for Portable or Transient Operations	No	The FRAC III Plant will not be a portable or transient operation.
§111.201-221	Outdoor Burning	Yes	Any outdoor burning that may be conducted at the FRAC III Plant will be done in accordance with these requirements.

5.1.3 30 TAC 112 - Control of Air Pollution from Sulfur Compounds

30 TAC 112 governs various sulfur compound emissions including sulfur dioxide, hydrogen sulfide, sulfuric acid, and total reduced sulfur compounds. The potential applicability of this chapter to sources in this application is explained in the following table. Brief explanations of compliance are provided for all applicable rules.

Section Number	Reference	Applicability	Compliance Explanation
§112.3-4	SO_2 Net Ground Level Concentrations	Yes	Upon TCEQ request, air dispersion modeling activities will be undertaken to demonstrate that the ground-level SO_2 concentrations standards specified in §112.3 will not be exceeded.
§112.5-7	Allowable SO_2 Emission Rates	No	There are no sulfuric acid or sulfur recovery plants in this permit application.

Section Number	Reference	Applicability	Compliance Explanation
§112.8	Allowable SO_2 Emission Rates	No	There are no solid fossil fuel-fired steam generators in this permit application.
§112.9	Allowable SO_2 Emission Rates	No	There will be no liquid fuel-fired steam generators, furnaces, or heaters in this permit application.
§112.14	Allowable SO_2 Emission Rates	No	The Project will not include any nonferrous smelters.
§112.15-18	Temporary Fuel Shortage Plan	No	Lone Star does not anticipate a shortage of low sulfur fuel.
§112.19-21	Area Control Plan	No	Lone Star does not anticipate needing relief from the requirements of §112.3.
§112.31-34	Allowable Emissions of H_2S	Yes	If Lone Star facilities in this application will produce H_2S emissions, Lone Star will comply with this rule. Upon request, Lone Star will conduct dispersion modeling to demonstrate compliance with the property line standards in this rule.
§112.41-47	Allowable Emissions of H_2SO_4	Yes	Any potential H_2SO_4 emissions will comply with this rule; however, none are expected.
§112.51-59	Emission Limits for Total Reduced Sulfur Compounds	No	The Site will not include a Kraft Pulp Mill.

5.1.4 30 TAC 113 - Hazardous Air Pollutant (HAP) Standards

30 TAC 113 addresses the control of air pollution from HAPs and other designated facilities, defined within this chapter to be certain air emissions from municipal solid waste landfills (MSWLFs), medical waste incinerators, and certain other processes/emissions regulated under 40 CFR Parts 61 and 63. The FRAC III Plant will not include a MSWLF or medical waste incinerator, nor is the FRAC III Plant anticipated to produce radionuclide emissions or be classified as a synthetic organic chemical manufacturing industry (SOCMI). Consequently, Subchapters B, D, and E are not applicable.

30 TAC 113 Subchapter C implements 40 CFR Part 63 by regulating HAP emissions released from source categories listed in this rule. The following paragraphs address the Project's applicability to source category regulations.

MACT HH (40 CFR Part 63 Subpart HH – National Emissions Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities) outlines specific requirements for major or area sources at oil and natural gas production facilities. The FRAC III Plant is an area source of HAPs and does not operate a TEG dehydration unit and thus is not subject to the requirements of this rule.

MACT ZZZZ (40 CFR Part 63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants (HAP) for Stationary Reciprocating Internal Combustion Engines (RICE) was amended and became effective August 20, 2010. Per 40 CFR §63.6590(c), stationary RICE that were constructed or reconstructed after June 12, 2006 located at an area source comply with MACT ZZZZ requirements by meeting the requirements of NSPS IIII. Two diesel generators (FINs: 3GEN.001 and 3GEN.002) and the firewater pump engine (FIN: 3PM18.044) are new RICE at an area source of HAPs and will comply with the requirements of NSPS IIII to comply with MACT ZZZZ.

MACT DDDDD (40 CFR Part 63 Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters) outlines specific requirements for industrial, commercial, and institutional boilers and process heaters at major sources of HAPs. The Site is not a major source of HAPs and is thus not subject to the requirements of this rule.

MACT JJJJJJ – National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boiler at Area Sources. Per 63.11195(e), gas-fired boilers as defined by this subpart are not subject to the requirements of this rule. Therefore, gas-fired hot oil heater (FIN 3HR15.001) and regenerator heater (FIN 3HR15.002) are not subject to the requirements of this rule.

5.1.5 30 TAC 114 - Control of Air Pollution from Motor Vehicles

The Site production operations will not include a motor vehicle fleet. Any on-site company vehicles will be used for maintenance only. Therefore, this chapter does not apply.

5.1.6 30 TAC 115 - Control of Air Pollution from Volatile Organic Compounds (VOC)

30 TAC Chapter 115 regulates VOC emissions according to source type and Site location (county). The Site will be located in Chambers County, which is defined as a part of the Houston/Galveston/Brazoria nonattainment area under this rule. Therefore, the potential applicability of the 30 TAC 115 sections is addressed in the following table. Brief explanations of compliance are provided for all applicable rules.

Section Number	Reference	Applicability	Compliance Explanation
§115.112-119	Storage of VOC	Yes	The FRAC III Plant will store materials in tanks with a capacity greater than 1,000 gallons with a true vapor pressure below 1.5 pounds per square inch absolute (psia); therefore, the tanks will be exempt from these requirements.

Section Number	Reference	Applicability	Compliance Explanation
§115.120-129	Vent Gas Control	Yes	The FRAC III Plant's vent gas streams will comply with these requirements.
§115.131-139	Water Separation	No	The FRAC III Plant will not operate VOC-Water separators, so these sections do not apply.
§115.140-149	Industrial Wastewater	No	The FRAC III Plant will not handle Industrial Wastewater, so these sections do not apply.
§115.152-159	Municipal Solid Waste Landfills	No	The FRAC III Plant will not have a Municipal Solid Waste Landfill, so these sections do not apply.
§115.160-169	Batch Processes	No	The FRAC III Plant will not include batch Processes, so these sections do not apply.
§115.211-259	VOC Transfer Operations	Yes	The FRAC III Plant will load and unload VOC with a true vapor pressure less than 0.5 psia; therefore, it is exempt from these requirements, except for inspection and recordkeeping requirements.
§115.311-359	Petroleum Refining, Natural Gas Processing, and Petrochemical Processes	Yes	The FRAC III Plant will implement 28LAER fugitive emissions monitoring program to comply with the requirements of this rule.
§115.412-419	Degreasing Processes	No	The FRAC III Plant will not include Solvent Degreasers, so these sections do not apply.
§115.420-429	Surface Coating Processes	No	The FRAC III Plant will not include Surface Coating Processes, so these sections do not apply.
§115.430-449	Printing Processes	No	Facilities in this application will not conduct printing operations as defined in these sections.
§115.510-559	Miscellaneous Industrial Sources	No	Facilities in this application will not conduct any of the miscellaneous industrial activities defined in this section.

Section Number	Reference	Applicability	Compliance Explanation
§115.600-629	Consumer-Related Sources and Products	No	Facilities in this application will not produce consumer products.
§115.720-789	Highly-Reactive Volatile Organic Compounds (HRVOC)	Yes	Lone Star will implement the 28 LAER fugitive emissions monitoring program to comply with the requirements of this rule. The process vents have a potential to emit less than 10 T/yr of HRVOC.
§115.901-950	Administrative Provisions	Yes	This rule contains the compliance dates and other administrative provisions. Lone Star will not be utilizing an alternative method of control or emission reduction credits to comply with the applicable Chapter 115 requirements.

5.1.7 30 TAC 117 - Control of Air Pollution from Nitrogen Compounds

30 TAC 117 governs NO_X emissions from the following types of facilities: Major Sources in an applicable ozone nonattainment area, acid manufacturers, and gas-fired combustion unit manufacturers, distributors, retailers, and installers. 30 TAC 117 also governs NO_X emissions from Minor Sources located in the Houston/Galveston ozone nonattainment area and sources located in specified counties in Central and East Texas. The Project will be located in Chambers County, designated as a severe nonattainment area for ozone. Brief explanations of compliance are provided for all applicable rules.

Section Number	Reference	Applicability	Compliance Explanation
§117.100-156	Combustion Control Beaumont–Port Arthur	No	The FRAC III Plant will not be within the geographic area of applicability.
§117.200-256	Combustion Control Dallas-Fort Worth	No	The FRAC III Plant will not be within the geographic area of applicability.
§117.300-356	Combustion Control Houston-Galveston-Brazoria	Yes	The FRAC III Plant will be within the geographic area of applicability; therefore, the Site will comply with these requirements.

Section Number	Reference	Applicability	Compliance Explanation
§117.400-456	Combustion Control Dallas/Fort Worth 8-Hour	No	The FRAC III Plant will not be within the geographic area of applicability.
§117.1000-1056	Combustion Control at Major Utility Electric Generation Sources Beaumont-Port Arthur	No	The FRAC III Plant will not be within the geographic area of applicability.
§117.1100-1156	Combustion Control at Major Utility Electric Generation Sources Dallas-Fort Worth	No	The FRAC III Plant will not be within the geographic area of applicability.
§117.1200-1256	Combustion Control at Major Utility Electric Generation Sources Houston-Galveston-Brazoria	No	The FRAC III Plant will not be a utility electric generation facility, so these sections do not apply.
§117.1300-1356	Combustion Control at Major Utility Electric Generation Sources Dallas-Fort Worth 8-Hour	No	The FRAC III Plant will not be within the geographic area of applicability.
§117.2000-2145	Combustion Control at Minor Sources	No	The FRAC III Plant will be a major source of NO_X, so these sections do not apply.
§117.3000-3345	Multi-Region Combustion Control	No	The FRAC III Plant will not be within the geographic area of applicability.
§117.4000-4210	Acid Manufacturing	No	The FRAC III Plant will not be an acid manufacturing facility, so these sections do not apply.

Section Number	Reference	Applicability	Compliance Explanation
§117.8000-8140	General Monitoring and Testing Requirements	Yes	The FRAC III Plant will comply with these requirements, as applicable.
§117.9000-9810	Compliance Schedule and Compliance Flexibility	Yes	The FRAC III Plant will comply with these requirements, as applicable.

5.1.8 30 TAC 118 - Control of Air Pollution Episodes

Lone Star will operate the FRAC III Plant in compliance with the TCEQ General Rules and the Air Pollution Episodic Requirements of 30 TAC 118.

5.1.9 30 TAC 122 - Federal Operating Permits

30 TAC 122 addresses the Texas implementation of the federal operating permits program promulgated under Title V of the Clean Air Act. Based on its potential to emit, as reflected by this application, the Project will be classified as a major modification to an existing major source. Consequently, Lone Star will submit an application for, and obtain approval of, a significant Title V operating permit revision prior to start of operation of the Project, in accordance with this rule.

5.1.10 Impact on Nearby Schools

As shown on the Figure 2-1 Area Map, no schools are located within 3,000 feet of the Site.

5.2 Measurement of Emissions - §116.111(a)(2)(B)

Upon agency request, Lone Star will provide provisions for the measurement of significant emissions, including the installation of sampling ports, platforms, etc.

5.3 Best Available Control Technology (BACT) - §116.111(a)(2)(C)

Refer to Section 4.0 for a BACT analysis.

5.4 New Source Performance Standards (NSPS) - §116.111(a)(2)(D)

New Source Performance Standards (NSPS) are found in 40 CFR Part 60 and outline specific requirements for certain types of new or modified sources. The following paragraphs describe the NSPS that potentially apply to the Project.

5.4.1 NSPS Db

NSPS Db (40 CFR 60, Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units) is applicable to steam generating units that commence construction, modification, or reconstruction after June 19, 1984, and that have a heat input capacity greater than 100 MMBtu/hr. The gas-fired hot oil heater (FIN: 3HR15.001) will be subject to the NO_X emission limitation of this subpart of 0.1 lb/MMBtu. The heater will comply with this requirement through the use of SCR. Lone Star will utilize a NO_X CEMS as required by this subpart, and will comply with the recordkeeping and reporting requirements of this rule.

5.4.2 NSPS Dc

NSPS Dc (40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units) outlines specific requirements for steam generating units built after June 9, 1989 with a heat duty between 10 MMBtu and 100 MMBtu. The gas-fired MS Regen Heater (FIN: 3HR15.002) will comply with the recordkeeping and reporting requirements of this subpart, as applicable.

5.4.3 NSPS Kb

NSPS Kb (40 CFR Part 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984) outlines specific requirements for storage vessels containing volatile organic liquids. NSPS Kb is not applicable to storage vessels with a capacity less than 75 cubic meters (472 barrels). All tanks at the FRAC III Plant will have a storage capacity less than 75 cubic meters; therefore, they will be exempt from NSPS Kb. The FRAC III Plant will also include pressurized vessels for refrigerant storage, which will be exempt from these requirements per 40 CFR 60.110b(d)(2).

5.4.4 NSPS KKK

NSPS KKK (40 CFR Part 60 Subpart KKK - Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing for which Construction, Reconstruction, or Modification commenced after January 20, 1984, and on or before August 23, 2011) is not applicable to the FRAC III Plant since construction will be commenced after the applicability date of August 23, 2011.

5.4.5 NSPS IIII

NSPS IIII (40 CFR Part 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines) outlines specific requirements for new or modified engines. According to Title 40 of the Code of Federal Regulations (40 CFR) §60.4200(a)(4), CI ICE commencing construction after July 11, 2005 are subject to these standards. The emergency diesel engines (FINs: 3GEN.001 and

3GEN.002) and the firewater pump engine (FIN: 3PM18.044) will be manufacturer-certified as compliant with NSPS IIII; therefore, they will meet the requirements of NSPS IIII.

5.4.6 NSPS OOOO

NSPS OOOO (40 CFR Part 60 Subpart OOOO – Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution) outlines requirements for well completions, pneumatic controllers, equipment leaks from natural gas processing plants, reciprocating compressors, centrifugal compressors, and storage vessels which are constructed, modified or reconstructed after August 23, 2011.

Standards applicable to storage vessels constructed, modified, or reconstructed after August 23, 2011 with VOC emissions greater than or equal to 6 T/yr will not apply to the FRAC III Plant storage tanks since the uncontrolled emissions are less than 6 T/yr.

The FRAC III Plant will be subject to the equipment leak standards for onshore natural gas processing plants. According to §60.5400 equipment leaks must comply with the requirements of §§ 60.482-1a(a), (b), and (d), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in § 60.5401. The Site will comply with the requirements of this rule with the following practices:

- Pumps in light liquid service will be monitored monthly to detect leaks and will be visually inspected every calendar week for indications of liquids dripping, and will follow the protocol for leak repairs as specified in §60.482-2a
- Relief valves in gas service emissions will be routed to the Plant Flare and will comply with the monitoring and inspection requirements of §60.482-11a in lieu of the requirements of §482-4a(a) and (b).
- Sampling connections will comply with the requirements of §60.482-5a through the use of closed-loop sampling that does not cause additional emissions during sampling. Also purged process fluid is returned to the process line. However, per §60.5401(c), sampling connections are not subject to the requirements of §60.482-5(a).
- Valves in vapor service and light liquid service will be monitored monthly to detect leaks as specified in §60.482-7a.
- Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service will be inspected and repaired as outlined in §60.482-8a.
- Connectors in vapor service and light liquid service will comply with the monitoring and repair requirements of §60.482-11a.
- The Site will comply with the recordkeeping requirements of §60.486a and reporting requirements of §60.487a as well as the additional requirements of §60.5421 and §60.5422.

The FRAC III Plant will include an amine unit to remove CO_2 and trace amounts of H_2S from the NGL stream. The requirements of Subpart OOOO will not apply to this amine unit since it does not process natural gas streams.

The Plant is not subject to any other NSPS requirements.

5.5 National Emission Standards for Hazardous Air Pollutants -§116.111(a)(2)(E)

National Emission Standards for Hazardous Air Pollutants (NESHAPs) have been established in 40 CFR Part 61 for various materials, including radon, beryllium, mercury, vinyl chloride, radionuclides, benzene, asbestos, and inorganic arsenic emissions from various types of sources. The FRAC III Plant will comply with any applicable subparts of this rule.

5.6 NESHAPs for Source Categories - §116.111 (a)(2)(F)

Additional NESHAPs (also known as MACT standards) have been established in 40 CFR Part 63 for various source categories and/or industries. The FRAC III Plant will be located at an area source of HAPs, and Lone Star will comply with any applicable requirements in these rules.

5.6.1 MACT HH

MACT HH (40 CFR Part 63 Subpart HH – National Emissions Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities) outlines specific requirements for major or area sources at oil and natural gas production facilities. As previously discussed, the FRAC III Plant will be located at an area source of HAPs and will not operate a TEG dehydration unit, and thus, will not be subject to the requirements of this rule.

5.6.2 MACT ZZZZ

MACT ZZZZ (40 CFR Part 63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines) outlines specific requirements for new or modified engines at major and area sources of HAPs. As stated previously, the emergency diesel engines and the firewater pump engine will meet the requirements of MACT ZZZZ by meeting NSPS IIII.

5.6.3 MACT DDDDD

MACT DDDDD (40 CFR 63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters) outlines specific requirements for industrial, commercial and institutional boilers and process heaters at major sources of HAPs. The Site will not be a major source of HAPs, and thus, will not be subject to the requirements of this rule.

5.6.4 MACT JJJJJJ

MACT JJJJJJ (40 CFR Part 63 Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers at Area Sources) outlines specific requirements for industrial, commercial, and institutional boilers at area sources of HAPs. Per 63.11195(e), gas-fired boilers as defined by this subpart are not subject to the requirements of this rule. Therefore, the gas-fired Hot Oil Heater (FIN: 3HR15.001) and MS Regen Heater (FIN: 3HR15.002) are not subject to the requirements of this rule.

5.7 Performance Demonstration - §116.111 (a)(2)(G)

The FRAC III Plant will be operated as represented in this application and will achieve the specified performance levels. Upon TCEQ request, additional information can be submitted to further demonstrate that operational levels and emission limitations are being upheld. Moreover, Lone Star will conduct performance tests in accordance with the applicable NSPS and MACT rules.

5.8 Nonattainment Review - §116.111(a)(2)(H)

The nonattainment new source review provisions specified in §116.150 are not applicable to GHG emissions. However, the FRAC III Plant did trigger nonattainment review for NO_X and VOC, for which an application has been submitted to the TCEQ.

5.9 Prevention of Significant Deterioration Review - §116.111(a)(2)(I)

The PSD review provisions specified in §116.160 are applicable to the Project because the proposed Project will be a major modification at an existing major source, as those terms are defined in 40 CFR §52.21. Therefore, the Project triggers PSD review for GHG under EPA permitting authority.

5.10 Air Dispersion Modeling - §116.111(a)(2)(J)

Because there is no National Ambient Air Quality Standard (NAAQS) for GHG, Lone Star is not conducting air dispersion modeling in support of this GHG PSD air permit application.

However, Lone Star will conduct an Air Quality Analysis (AQA) for the Project to demonstrate that the proposed Project off-site contaminant impacts will be in compliance with state and federal requirements upon TCEQ request.

5.11 Hazardous Air Pollutants - 116.111(a)(2)(K)

The FRAC III Plant will be located at an area source of HAPs and will not be subject to 30 TAC Chapter 116, Subchapter E. Project sources will comply with MACT standards promulgated under 40 CFR Part 63, as previously discussed.

5.12 Mass Cap and Trade Allowances - 116.111 (a)(2)(L)

The FRAC III Plant will be located in the Houston/Galveston area and will be subject to Chapter 101, Subchapter H, Division 3 relating to the Mass Emissions Cap and Trade Program. Lone Star will obtain the necessary allowances prior to start of operations.

6 AIR QUALITY ANALYSIS

This section of Lone Star's GHG PSD air permit application addresses the air quality analysis requirements for the FRAC III Plant. As stated previously, because there is no NAAQS for GHG, Lone Star is not conducting GHG air dispersion modeling for the Project.

Ambient monitoring for GHG is not required because EPA regulations provide an exemption in sections §52.21(i)(5)(iii) and 51.166(i)(5)(iii) for pollutants that are not listed in the appropriate section of the regulations, and GHG are not currently included in that list. Sections §52.21(m)(1)(ii) and §51.166(m)(1)(ii) of EPA's regulations apply to pollutants for which no NAAQS exists. However, GHG is not considered to effect ambient air quality as defined in Section §52.21(m)(1)(ii) or §51.166(m)(1)(ii) as was intended when these rules were written. This approach is consistent with the EPA Tailoring Rule which includes the following statement with respect to these requirements:

> *"There are currently no NAAQS or PSD increments established for GHG, and therefore these PSD requirements would not apply for GHG, even when PSD is triggered for GHG."*

Because there is currently no NAAQS or PSD increment established for GHG, no further assessment is required.

7 REFERENCES

The following references have been used in the preparation of this PSD air permit application document. Where appropriate, certain materials have been included in the appendices to this document.

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APPENDIX A
TCEQ AIR PERMIT APPLICATION FORMS AND TABLES

FRAC III PROJECT GHG PSD AIR PERMIT APPLICATION

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

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 — Mont Belvieu Gas Plant Air 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 604309419		RN 106018260

SECTION II: Customer Information

5. Effective Date for Customer Information Updates (mm/dd/yyyy): 5/3/2013

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**

*<u>**If "No Change" and Section I is complete, skip to Section III – Regulated Entity Information.</u>*

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)*

Mont Belvieu Gas Plant

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
Mont Belvieu	Chambers	Texas	77520

37. Latitude (N) In Decimal:	29.85066		38. Longitude (W) In Decimal:	-94.910345	
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
29	51	2	-94	54	37

*Coordinates are in NAD 83

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:	Jeff Weiler	41. Title:	Senior Environmental Manager
42. Telephone Number	43. Ext./Code	44. Fax Number	45. E-Mail Address
(210) 403-7323		(210) 403-7523	jeff.weiler@energytransfer.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:	Lone Star NGL Fractionators LLC	Job Title:	Senior Environmental Manager
Name *(In Print)*:	Jeff Weiler	Phone:	(210) 403-7323
Signature:	[signature]	Date:	5/15/10

Texas Commission on Environmental Quality
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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: Lone Star NGL Fractionators LLC		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: Mr. Clint Cowan		
Title: Vice President - Environmental		
Mailing Address: 800 E. Sonterra Blvd., Suite 400		
City: San Antonio	State: Texas	ZIP Code: 78258
Telephone No.: (210) 403-7470	Fax No.: (210) 403-7670	E-mail Address: clint.cowan@energytransfer.com
C. Technical Contact Name: Mr. Jeff Weiler		
Title: Senior Environmental Manager		
Company Name: Lone Star NGL Fractionators LLC		
Mailing Address: 800 E. Sonterra Blvd., Suite 400		
City: San Antonio	State: Texas	ZIP Code: 78258
Telephone No.: (210) 403-7323	Fax No.: (210) 403-7523	E-mail Address: jeff.weiler@energytransfer.com
D. Site Name: Mont Belvieu Gas Plant		
E. Area Name/Type of Facility: Natural Gas Processing Plant		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Natural Gas and NGL Treating & Processing Plant		
Principal Standard Industrial Classification Code (SIC): 1321		
Principal North American Industry Classification System (NAICS): 211112		
G. Projected Start of Construction Date: N/A		
Projected Start of Operation Date: N/A		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 9850 FM 1942		
City/Town: Baytown	County: Chambers	ZIP Code: 77521
Latitude (nearest second): 29° 51' 0"	Longitude (nearest second): -94° 54' 37"	

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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): CN604309419	
L.	Regulated Entity Number (RN): RN106018260	
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:	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: Senator Tommy Williams		District No.: 4
State Representative: Representative Craig Eiland		District No.: 23
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

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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:	
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.): O-3586	
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	

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III.	**Type of Permit Action Requested *(continued)***	
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2.	Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***	
☐ GOP Issued	☐ GOP application/revision application submitted or under APD review	
☐ SOP Issued	☒ SOP application/revision application submitted or under APD review	
IV.	**Public Notice Applicability**	
A.	Is this a new permit application or a change of location application?	☒ YES ☐ NO
B.	Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C.	Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☐ YES ☒ NO
D.	Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES ☒ NO
If Yes, list the affected state(s) and/or Class I Area(s).		
List:		
E.	Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.	
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 (SO2):		
Carbon Monoxide (CO):		
Nitrogen Oxides (NOx):		
Particulate Matter (PM):		
PM 10 microns or less (PM10):		
PM 2.5 microns or less (PM2.5):		
Lead (Pb):		
Hazardous Air Pollutants (HAPs):		
Other speciated air contaminants not listed above:		

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V. Public Notice Information *(complete if applicable)*		
A. Public Notice Contact Name: Ms. Cynthia Pate		
Title: Environmental Manager		
Mailing Address: 10902 Fitzgerald Road, P.O. Box 250		
City: Mont Belvieu	State: Texas	ZIP Code: 77580
B. Name of the Public Place: Chambers County Courthouse, County Clerk's Office		
Physical Address *(No P.O. Boxes)*: 404 Washington Avenue		
City: Anahuac	County: Chambers	ZIP Code: 77514
The public place has granted authorization to place the application for public viewing and copying.		☒ YES ☐ NO
The public place has internet access available for the public.		☒ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable: Judge Jimmy Silvia		
Mailing Address: 404 Washington Avenue		
City: Anahuac	State: Texas	ZIP Code: 77514
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:		
Mailing Address:		
City:	State:	ZIP Code:
Name of the Indian Governing Body:		
Mailing Address:		
City:	State:	ZIP Code:

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	
2.	☒ Plot Plan	
3.	☒ Existing Authorizations	
4.	☒ Process Flow Diagram	
5.	☒ Process Description	
6.	☒ Maximum Emissions Data and Calculations	
7.	☒ Air Permit Application Tables	
a.	☒ Table 1(a) (Form 10153) entitled, Emission Point Summary	
b.	☐ Table 2 (Form 10155) entitled, Material Balance	
c.	☒ Other equipment, process or control device tables	
B.	Are any schools located within 3,000 feet of this facility?	☐ YES ☒ NO

VII.	**Technical Information**			
C.	Maximum Operating Schedule:			
Hour(s): 24	Day(s): 7	Week(s): 52	Year(s): 8760 hrs/yr	
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

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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:		
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

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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: Clint Cowan	
Signature: Clint Cowan *Original Signature Required*	
Date: 5/10/13	

PRINT FORM RESET FORM

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emissions Point Summary

Permit Number:	TBD	RN Number:	RN106018260	Date:	June-13
Company Name:	Lone Star NGL Fractionators LLC				

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			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate [a]		4. UTM Coordinates of Emission Point			5. Building Height (ft)	6. Height Above Ground	Source: 7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	NAME (C)		Pounds per Hour (A)	TPY (B)	Zone	East (meters)	North (meters)			Diameter (ft) (A)	Velocity (fps) (B)	Tempera-ture (C)	Length (ft) (A)	Width (ft) (B)	Axis Degrees (C)
3SK25.002	3SK25.002, 3HT16.005	FRAC III Thermal Oxidizer	CO_2e	--	51,357.18	15	315,653	3,303,849	--	180.0	2	28.3	1,400	--	--	--
3HR15	3HR15.001	FRAC III Hot Oil Heater (Normal Operations)	CO_2e	--	129,816.86	15	315,622	3,303,826	--	100.0	7.6	42.3	555	--	--	--
3HR15	3HR15.001	FRAC III Hot Oil Heater (Startup/Shutdown)	CO_2e	--	745.22	15	315,622	3,303,826	--	100.0	7.6	42.3	555	--	--	--
3HR15	3HR15.002	FRAC III Regenerator Heater (Normal Operations)	CO_2e	--	35,624.16	15	315,622	3,303,826	--	100.0	7.6	42.3	555	--	--	--
3HR15	3HR15.002	FRAC III Regenerator Heater (Startup/Shutdown)	CO_2e	--	204.50	15	315,622	3,303,826	--	100.0	7.6	42.3	555	--	--	--
1SK25.001	1SK25.001	Plant Flare (FRAC III Waste Gas Only)	CO_2e	--	396.56	15	315,661	3,303,409	--	415	4.5	109	1,000	--	--	--
3FUG	3FUG	FRAC III Fugitives	CO_2e	--	12.88	15	315,658	3,303,912	--	--	--	--	--	700	250	--
3GEN.001	3GEN.001	FRAC III Emergency Diesel Generator 1	CO_2e	--	15.01	15	315,658	3,303,912		20.0	0.67	150.33	950	--	--	--
3GEN.002	3GEN.002	FRAC III Emergency Diesel Generator 2	CO_2e	--	16.78	15	315,658	3,303,912		20.0	0.67	150.33	950	--	--	--
3PM18.044	3PM18.044	FRAC III Firewater Pump	CO_2e	--	15.01	15	315,658	3,303,912		20.0	0.67	150.33	950	--	--	--
3MSS1	3MSS1	FRAC III Miscellaneous Maintenance	CO_2e	--	0.10	15	315,658	3,303,912	--	--	--	--	--	700	250	--

[a] All emission rates are estimated values only and should not be considered maximum allowable emission rates.

TABLE 4

COMBUSTION UNITS

OPERATIONAL DATA	
Number from flow diagram: 3SK25.002	Model Number(if available):
Name of device: Frac III Thermal Oxidizer	Manufacturer

CHARACTERISTICS OF INPUT

	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
Waste Material*	1. Waste Gas	538	538	538
	2.			
	3.			
	4.			
	5.			

Gross Heating Value of Waste Material (Wet basis if applicable)	Btu/lb	Air Supplied for Waste Material	Minimum SCFM (70°F & 14.7 psia)	Maximum SCFM(70°F & 14.7 psia)
	23,976		0	0

Waste Material of Contaminated Gas	Total Flow Rate lb/hr		Inlet Temperature °F	
	Minimum Expected	Design Maximum	Minimum Expected	Design Maximum

	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
Fuel	1. Nat. Gas/Ethane	5 MMBtu/hr	5 MMBtu/hr	5 MMBtu/hr
	2.			
	3.			
	4.			

Gross Heating Value of Fuel	Btu/lb	Air Supplied for Fuel	Minimum SCFM (70°F & 14.7 psia)	Maximum SCFM(70°F & 14.7 psia)
	1,027 Btu/scf 1,783 Btu/scf		0	0

*Describe how waste material is introduced into combustion unit on an attached sheet. Supply drawings, dimensioned and to scale to show clearly the design and operation of the unit.

TABLE 4
(continued)

COMBUSTION UNITS

CHARACTERISTICS OF OUTPUT				
Flue Gas Released	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
	1.			
	2.			
	3.			
	4.			
	5.			

Temperature at Stack Exit °F	Total Flow Rate lb/hr		Velocity at Stack Exit ft/sec	
	Minimum Expected	Maximum Expected	Minimum Expected	Maximum Expected
1,500			28.3	28.3

COMBUSTION UNIT CHARACTERISTICS		
Chamber Volume from Drawing ft^3	Chamber Velocity at Average Chamber Temperature ft/sec	Average Chamber Temperature °F
Average Residence Time sec	Exhaust Stack Height ft	Exhaust Stack Diameter ft
	180	2

ADDITIONAL INFORMATION FOR CATALYTIC COMBUSTION UNITS		
Number and Type of Catalyst Elements	Catalyst Bed Velocity ft/sec	Max. Flow Rate per Catalytic Unit (Manufacturer's Specifications) Specify Units
N/A	N/A	N/A

Attach separate sheets as necessary providing a description of the combustion unit, including details regarding principle of operation and the basis for calculating its efficiency. Supply an assembly drawing, dimensioned and to scale, to show clearly the design and operation of the equipment. If the device has bypasses, safety valves, etc., specify when such bypasses are to be used and under what conditions. Submit explanations on control for temperature, air flow rates, fuel rates, and other operating variables.

10/93

TABLE 6

BOILERS AND HEATERS

Type of Device: FRAC III Hot Oil Heater		Manufacturer: John Zink	
Number from flow diagram: EPN: 3HR15/FIN: 3HR15.001		Model Number:	
CHARACTERISTICS OF INPUT			
Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)
Natural Gas or Ethane			Average 3,489 or 2,010 scfm / Design Maximum
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air
		(specify units) 1,027 or 1,783 Btu/scf	Average _____ scfm* 15 % excess (vol) / Design Maximum _____ scfm * 15 % excess (vol)

HEAT TRANSFER MEDIUM						
Type Transfer Medium	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Design Maxim
Oil						

OPERATING CHARACTERISTICS			
Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS					
Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
7.6 feet	100 feet	33.2		555	90,422

CHARACTERISTICS OF OUTPUT	
Material	Chemical Composition of Exit Gas Released (% by Volume)
	See Table 1(a) for EPN 3HR15

Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.

Also supply an assembly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit.Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F,14.7 psia

08/93

TABLE 6

BOILERS AND HEATERS

Type of Device: FRAC III MS Regen Heater		Manufacturer: John Zink	
Number from flow diagram: EPN: 3HR15/FIN: 3HR15.002		Model Number:	
CHARACTERISTICS OF INPUT			
Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)
Natural Gas or Ethane			Average 957 or 552 scfm / Design Maximum
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air
		(specify units) 1,027 or 1,783 Btu/scf	Average ____ scfm* 15 % excess (vol) / Design Maximum ____ scfm * 15 % excess (vol)

HEAT TRANSFER MEDIUM						
Type Transfer Medium	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Design Maxim
Oil						

OPERATING CHARACTERISTICS			
Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS					
Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
7.6 feet	100 feet	9.1		555	24,814

CHARACTERISTICS OF OUTPUT	
Material	Chemical Composition of Exit Gas Released (% by Volume)
	See Table 1(a) for EPN 3HR15

Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.

Also supply an assembly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit.Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F,14.7 psia

08/93

TABLE 8

FLARE SYSTEMS

Number from Flow Diagram	Manufacturer & Model No. (if available)
1SK25.001	

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected (scfm [68°F,14.7 psia])	Ave. Value Expected (scfm [68°F, 14.7 psia])	Design Max. (scfm [68°F, 14.7 psia])
	1. Fuel Gas	0	0 (1)	
	2. Waste Gas	0	289 (2)	
	3. Propane	0	26 (3)	
	4.			
	5.			
	6.			
	7.			
	8.			
% of time this condition occurs		0%	100%	0%

	Flow Rate (scfm [68°F, 14.7 psia]) Minimum Expected	Flow Rate (scfm [68°F, 14.7 psia]) Design Maximum	Temp. °F	Pressure (psig)
Waste Gas Stream	0	1,006	69.78	800
Fuel Added to Gas Steam				

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot

For Stream Injection	Stream Pressure (psig) Min. Expected	Stream Pressure (psig) Design Max.	Total Stream Flow Rate (lb/hr)	Temp. °F	Velocity (ft/sec)

	Number of Jet Streams	Diameter of Steam Jets (inches)	Design basis for steam injected (lb steam/lb hydrocarbon)

For Water Injection	Water Pressure (psig) Min.Expected Design Max.	Total Water Flow Rate (gpm) Min. Expected Design Max.	No. of Water Jets	Diameter of Water Jets (inches)

Flare Height (ft)	415	Flare tip inside diameter (ft)	
Capital Installed Cost $____________		Annual Operating Cost $______________	

Supply an assembly drawing, dimensioned and to scale, to show clearly the operation of the flare system. Show interior dimensions and features of the equipment necessary to calculate its performance. Also describe the type of ignition system and its method of operation. Provide an explanation of the control system for steam flow rate and other operating variables.

05/96

(1) Fuel gas stream from FRAC I only (pre-Tailoring Rule).
(2) Waste gas stream includes FRAC III only (waste streams from FRAC I, II, and Export FRAC excluded).
(3) Propane steam includes FRAC III only (waste streams from FRAC I, II, and Export FRAC excluded).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data			
Manufacturer:	Model No.	Serial No.	Manufacture Date: Post June 12, 2006
Rebuilds Date:	No. of Cylinders:	Compression Ratio:	EPN: 3GEN.001

Application: ☐ Gas Compression ☒ Electric Generation ☐ Refrigeration ☒ Emergency/Stand by

☐ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☐ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: Variable:

Manufacture Horsepower Rating: 447 kW | Proposed Horsepower Rating: 447 kW

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (°F)	Exit Velocity (FPS)
20	0.67	950	150.33

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 110 lb/hr | Heat Value: 19,300 Btu/lb (HHV) | 19,300 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %):

III. Emission Factors (Before Control) Note: All factors, except SO2, are in g/kW-hr

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.0		3.50			15	4.0				0.20	

Source of Emission Factors: ☐ Manufacturer Data ☐ AP-42 ☒ Other (specify): NSPS IIII

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):__________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☐ Yes ☒ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☒ NSPS IIII ☒ Title 30 Chapter 117 - List County: Chambers

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

TCEQ

I. Engine Data			
Manufacturer:	Model No.	Serial No.	Manufacture Date: Post June 12, 2006
Rebuilds Date:	No. of Cylinders:	Compression Ratio:	EPN: 3GEN.002

Application: ☐ Gas Compression ☒ Electric Generation ☐ Refrigeration ☒ Emergency/Stand by

☐ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☐ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: | Variable:

Manufacture Horsepower Rating: 500 kW | Proposed Horsepower Rating: 500 kW

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (^oF)	Exit Velocity (FPS)
20	0.67	950	150.33

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 110 lb/hr | Heat Value: 19,300 Btu/lb (HHV) | 19,300 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %):

III. Emission Factors (Before Control) Note: All factors, except SO2, are in g/kW-hr

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.0		3.50			15	4.0				0.20	

Source of Emission Factors: ☐ Manufacturer Data ☐ AP-42 ☒ Other (specify): NSPS IIII

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):__________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☐ Yes ☒ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☒ NSPS IIII ☒ Title 30 Chapter 117 - List County: Chambers

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data			
Manufacturer:	Model No.	Serial No.	Manufacture Date: Post June 12, 2006
Rebuilds Date:	No. of Cylinders:	Compression Ratio:	EPN: 3PM18.044

Application: ☐ Gas Compression ☒ Electric Generation ☐ Refrigeration ☒ Emergency/Stand by

☐ 4 Stroke Cycle ☐ 2 Stroke Cycle ☐ Carbureted ☐ Spark Ignited ☐ Dual Fuel ☐ Fuel Injected

☒ Diesel ☐ Naturally Aspirated ☐ Blower /Pump Scavenged ☐ Turbo Charged and I.C. ☐ Turbo Charged

☐ Intercooled ☐ I.C. Water Temperature ☐ Lean Burn ☐ Rich Burn

Ignition/Injection Timing: Fixed: | Variable:

Manufacture Horsepower Rating: 447 kW | Proposed Horsepower Rating: 447 kW

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (^{o}F)	Exit Velocity (FPS)
20	0.67	950	150.33

II. Fuel Data

Type of Fuel: ☐ Field Gas ☐ Landfill Gas ☐ LP Gas ☐ Natural Gas ☐ Digester Gas ☒ Diesel

Fuel Consumption (BTU/bhp-hr): 110 lb/hr | Heat Value: 19,300 Btu/lb (HHV) | 19,300 Btu/lb (LHV)

Sulfur Content (grains/100 scf - weight %):

III. Emission Factors (Before Control) Note: All factors, except SO2, are in g/kW-hr

NO_X		CO		SO_2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv
4.0		3.50			15	4.0				0.20	

Source of Emission Factors: ☐ Manufacturer Data ☐ AP-42 ☒ Other (specify): NSPS IIII

IV. Emission Factors (Post Control)

NO_X		CO		SO2		VOC		Formaldehyde		PM10	
g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv	g/hp-hr	ppmv

Method of Emission Control: ☐ NSCR Catalyst ☐ Lean Operation ☐ Parameter Adjustment

☐ Stratified Charge ☐ JLCC Catalyst ☐ Other (Specify):____________________

Note: *Must submit a copy of any manufacturer control information that demonstrates control efficiency.*

Is Formaldehyde included in the VOCs? ☐ Yes ☒ No

V. Federal and State Standards (Check all that apply)

☐ NSPS JJJJ ☒ MACT ZZZZ ☒ NSPS IIII ☒ Title 30 Chapter 117 - List County: Chambers

VI. Additional Information

1. Submit a copy of the engine manufacturer's site rating or general rating specification data.
2. Submit a typical fuel gas analysis, including sulfur content and heating value. For gaseous fuels, provide mole percent of constituents.
3. Submit description of air/fuel ratio control system (manufacturer information is acceptable).

APPENDIX B
EMISSION RATE CALCULATIONS

FRAC III PROJECT GHG PSD AIR PERMIT APPLICATION

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

Description **Page**

TABLE B-1

SUMMARY OF SITE-WIDE GREENHOUSE GASES EMISSION RATES

FRAC III PROJECT GHG PSD AIR PERMIT APPLICATION

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

EPN	FIN	Description	CO_2 Annual[a] (T/yr)	CH_4 Annual[a] (T/yr)	N_2O Annual[a] (T/yr)	CO_2e Annual[a] (T/yr)
3SK25.002	3SK25.002, 3HT16.005	FRAC III Thermal Oxidizer	51,341.08	0.16	0.04	51,357.18
3HR15	3HR15.001	FRAC III Hot Oil Heater (Normal Operations)	129,302.87	6.19	1.24	129,816.86
3HR15	3HR15.001	FRAC III Hot Oil Heater (Startup/Shutdown)	742.27	0.04	0.01	745.22
3HR15	3HR15.002	FRAC III Regenerator Heater (Normal Operations)	35,483.11	1.70	0.34	35,624.16
3HR15	3HR15.002	FRAC III Regenerator Heater (Startup/Shutdown)	203.69	0.01	0.00	204.50
1SK25.001	1SK25.001	Plant Flare (FRAC III Waste Gas Only)	396.21	0.008	0.0006	396.56
3FUG	3FUG	FRAC III Fugitives	0.003	0.613	--	12.88
3GEN.001	3GEN.001	FRAC III Emergency Diesel Generator 1	14.96	0.001	0.0001	15.01
3GEN.002	3GEN.002	FRAC III Emergency Diesel Generator 2	16.73	0.001	0.0001	16.78
3PM18.044	3PM18.044	FRAC III Firewater Pump	14.96	0.001	0.0001	15.01
3MSS1	3MSS1	FRAC III Miscellaneous Maintenance	0.0002	0.005	--	0.10
		TOTAL:	**217,516**	**8.72**	**1.63**	**218,204**
		PSD Major Source Threshold:	**-**	**-**	**-**	**100,000**
		PSD Major Modification Threshold:	**-**	**-**	**-**	**75,000**

COMBUSTION SOURCES POTENTIAL TO EMIT GREENHOUSE GASES
FRAC III PROJECT GHG PSD AIR PERMIT APPLICATION
MONT BELVIEU GAS PLANT
LONE STAR NGL FRACTIONATORS LLC

Combustion Source	Description	HP	Btu/hp-hr	MMBtu/hr	Annual Operating Hours	Fuel Usage MMBtu/yr	CO_2 [a] Emissions short T/yr	CH_4 [a] Emissions short T/yr	N_2O [a] Emissions short T/yr	CO_2e[a] short T/yr	GHG Mass[a] short T/yr
3GEN.001	FRAC III Emergency Diesel Generator 1	600	8,500	5.10	36	183.45	14.96	0.001	0.0001	15.01	14.96
3GEN.002	FRAC III Emergency Diesel Generator 2	671	8,500	5.70	36	205.17	16.73	0.001	0.0001	16.78	16.73
3PM18.044	FRAC III Firewater Pump	600	8,500	5.10	36	183.45	14.96	0.001	0.0001	15.01	14.96
3HR15.001	FRAC III Hot Oil Heater (Normal Operations, Natural Gas-Fired)	---	---	215.0	8,710	1,872,650.00	109,445.06	2.06	0.21	109,552.40	109,447.33
	FRAC III Hot Oil Heater (Normal Operations, Ethane-Fired)	---	---	215.0	8,710	1,872,650.00	129,302.87	6.19	1.24	129,816.86	129,310.30
	Maximum Emission Rate (Normal Operations)						129,302.87	6.19	1.24	129,816.86	129,310.30
3HR15.001	FRAC III Hot Oil Heater (Startup/Shutdown, Natural Gas-Fired)	---	---	215.0	50	10,750.00	628.27	0.01	0.00	628.89	628.29
3HR15.001	FRAC III Hot Oil Heater (Startup/Shutdown, Ethane-Fired)	---	---	215.0	50	10,750.00	742.27	0.04	0.01	745.22	742.31
	Maximum Emission Rate (Startup/Shutdown)						742.27	0.04	0.01	745.22	742.31
3HR15.002	FRAC III Regenerator Heater (Normal Operations, Natural Gas-Fired)	---	---	59.0	8,710	513,890.00	30,033.76	0.57	0.06	30,063.22	30,034.38
3HR15.002	FRAC III Regenerator Heater (Normal Operations, Ethane-Fired)	---	---	59.0	8,710	513,890.00	35,483.11	1.70	0.34	35,624.16	35,485.15
	Maximum Emission Rate (Normal Operations)						35,483.11	1.70	0.34	35,624.16	35,485.15
3HR15.002	FRAC III Regenerator Heater (Startup/Shutdown, Natural Gas-Fired)	---	---	59.0	50	2,950.00	172.41	0.00	0.00	172.58	172.41
3HR15.002	FRAC III Regenerator Heater (Startup/Shutdown, Ethane-Fired)	---	---	59.0	50	2,950.00	203.69	0.01	0.00	204.50	203.70
	Maximum Emission Rate (Startup/Shutdown)						203.69	0.01	0.00	204.50	203.70
3SK25.002 (Fuel Gas)	FRAC III Thermal Oxidizer (Natural Gas-Fired)	---	---	5.00	8,760	43,800.00	2,559.84	0.05	0.00	2,562.36	2,559.90
3SK25.002 (Fuel Gas)	FRAC III Thermal Oxidizer (Ethane-Fired)	---	---	5.00	8,760	43,800.00	3,024.31	0.14	0.03	3,036.33	3,024.48
	Maximum Emission Rate						3,024.31	0.14	0.03	3,036.33	3,024.48
3SK25.002 (Waste Gas)[b]	FRAC III Amine Unit to Thermal Oxidizer	---	---	---	---	---	48,316.78	0.01	0.01	48,320.86	48,316.80
1SK25.001 (Waste Gas)[b]	FRAC III MSS and FRAC III Piping Vents to Flare	---	---	---	---	---	396.21	0.01	0.001	396.56	396.22
						TOTAL:	**217,515.88**	**8.10**	**1.63**	**218,191.29**	**217,525.61**

[a]Sample calculations:

CO_2, CH_4, or N_2O = Fuel * HHV * EF (Eq. C-1, §98.33(a)(1)(i) and C-8, §98.33(c)(1))

Where:

CO_2, CH_4, or N_2O = Annual emissions from combustion in kilograms
Fuel = volume combusted, scf/yr
HHV = High heat value of fuel, MMBtu/scf
EF = Emission Factors from Tables C-1 and C-2 of 40 CFR 98, Subpart C are as follows:

Compound	Natural Gas (kg/MMBtu)	Diesel (kg/MMBtu)	Ethane (kg/MMBtu)
CO_2	53.02	73.96	62.64
CH_4	0.001	0.003	0.003
N_2O	0.0001	0.0006	0.0006

The engine design rating in MMBtu/hr was substituted for Fuel and HHV in Equation C-1 and a conversion from metric tons to short tons was applied in the following sample calculation for 3GEN.001:

CO_2(short T/yr) = (0.001 metric T/kg)*(Fuel usage, MMBtu/yr))*[CO_2 EF, kg/MMBtu] * (2,204.6 lb/metric T) / (2,000 lb/short T)
= 14.96 short T/yr

An example calculation for CO_2e in using Eq. A-1 and global warming potential factors found in Table A-1:
CO_2e (short T/yr) = (CO_2 Emission, short T/yr) + 21 * (CH_4 Emission, short T/yr) + 310 * (N_2O Emission, short T/yr)
= 15.01 short T/yr

An example calculation for GHG Mass in short T/yr for EPN 3GEN.001 follows:
GHG Mass (short T/yr) = (CO_2 Emission, short T/yr) + (CH_4 Emission, short T/yr) + (N_2O Emission, short T/yr)
= 14.96 short T/yr

[b]Waste gas combustion GHG emissions from the flares and thermal oxidizers are calculated on the following sheets.

FRAC III PLANT PIPING FUGITIVES POTENTIAL TO EMIT GREENHOUSE GASES

FRAC III PROJECT GHG PSD AIR PERMIT APPLICATION

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

Component/Stream	Number of Components	Emission Factors [a] (lb/hr-component)	Operating Hours (hr/yr)	Maximum VOC Content (%)	Maximum Benzene Content (%)	Maximum CO_2 Content (%)	Maximum CH_4 Content (%)	Reduction Credit [a] (%)	PTE CO_2 Annual [c] (T/yr)	PTE CH_4 Annual [c] (T/yr)	PTE CO_2e Annual [c] (T/yr)
Valves											
Gas (Natural Gas)	56	0.00992	8,760	7%	0%	4%	85%	97%	0.0027	0.0620	1.3049
Gas (Ethane)	452	0.0089	8,760	1%	0%	0%	1%	0%	0.0000	0.1125	2.3615
Gas (Propane)	662	0.0089	8,760	100%	0%	0%	0%	97%	0.0000	0.0000	0.0000
Gas (Propylene)	646	0.0089	8,760	100%	0%	0%	0%	97%	0.0000	0.0000	0.0000
Gas (Butane)	454	0.0089	8,760	100%	0%	0%	0%	97%	0.0000	0.0000	0.0000
Gas (Isobutane)	931	0.0089	8,760	100%	0%	0%	0%	97%	0.0000	0.0000	0.0000
Light Liquid (Methanol)	11	0.0035	8,760	100%	0%	0%	0%	97%	0.0000	0.0000	0.0000
Light Liquid (Natural Gasoline)	520	0.0000948	8,760	100%	1%	0%	0%	97%	0.0000	0.0000	0.0000
Light Liquid (NGL)	1,106	0.0055	8,760	80%	1.2%	0%	0.19%	97%	0.0000	0.0015	0.0317
Water/Oil	96	0.000216	8,760	100%	0%	0%	0%	0%	0.0000	0.0000	0.0000
Heavy Liquid	1,002	0.0000185	8,760	100%	0%	0%	0%	0%	0.0000	0.0000	0.0000
Relief Valves											
Gas (Natural Gas)	4	0.0194	8,760	7%	0%	4%	85%	100%	0.0000	0.0000	0.0000
Gas (Ethane)	4	0.2293	8,760	1%	0%	0%	1%	100%	0.0000	0.0000	0.0000
Gas (Propane)	0	0.2293	8,760	100%	0%	0%	0%	100%	0.0000	0.0000	0.0000
Gas (Butane)	3	0.2293	8,760	100%	0%	0%	0%	100%	0.0000	0.0000	0.0000
Gas (Isobutane)	3	0.2293	8,760	100%	0%	0%	0%	100%	0.0000	0.0000	0.0000
Light Liquid (Methanol)	0	0.0165	8,760	100%	0%	0%	0%	100%	0.0000	0.0000	0.0000
Light Liquid (Natural Gasoline)	8	0.0165	8,760	100%	1%	0%	0%	100%	0.0000	0.0000	0.0000
Light Liquid (NGL)	29	0.0165	8,760	80%	1.2%	0%	0.19%	100%	0.0000	0.0000	0.0000
Water/Oil	2	0.0309	8,760	100%	0%	0%	0%	0%	0.0000	0.0000	0.0000
Heavy Liquid	23	0.0000683	8,760	100%	0%	0%	0%	0%	0.0000	0.0000	0.0000
Compressor Seals											
Gas (Natural Gas)	0	0.0194	8,760	7%	0%	4%	85%	95%	0.0000	0.0000	0.0000
Gas (Propylene)	2	0.5027	8,760	100%	0%	0%	0%	95%	0.0000	0.0000	0.0000
Gas (Isobutane)	3	0.5027	8,760	100%	0%	0%	0%	95%	0.0000	0.0000	0.0000
Pump Seals [d]											
Gas (Natural Gas)	0	0.00529	8,760	7%	0%	4%	85%	93%	0.0000	0.0000	0.0000
Gas (Ethane)	6	0.00529	8,760	1%	0%	0%	1%	0%	0.0000	0.0009	0.0186
Gas (Propane)	6	0.00529	8,760	100%	0%	0%	0%	93%	0.0000	0.0000	0.0000
Gas (Propylene)	4	0.00529	8,760	100%	0%	0%	0%	93%	0.0000	0.0000	0.0000
Gas (Butane)	10	0.00529	8,760	100%	0%	0%	0%	93%	0.0000	0.0000	0.0000
Gas (Isobutane)	6	0.00529	8,760	100%	0%	0%	0%	93%	0.0000	0.0000	0.0000
Light Liquid (Methanol)	2	0.0386	8,760	100%	0%	0%	0%	93%	0.0000	0.0000	0.0000
Light Liquid (Natural Gasoline)	6	0.00119	8,760	100%	1%	0%	0%	93%	0.0000	0.0000	0.0000
Light Liquid (NGL)	7	0.02866	8,760	80%	1.2%	0%	0.19%	93%	0.0000	0.0001	0.0024
Water/Oil	2	0.000052	8,760	100%	0%	0%	0%	0%	0.0000	0.0000	0.0000
Heavy Liquid	13	0.00113	8,760	100%	0%	0%	0%	0%	0.0000	0.0000	0.0000
Connectors											
Gas (Natural Gas)	87	0.00044	8,760	7%	0%	4%	85%	97%	0.0002	0.0043	0.0899
Gas (Ethane)	1,152	0.0029	8,760	1%	0%	0%	1%	0%	0.0000	0.0934	1.9616
Gas (Propane)	1,902	0.0029	8,760	100%	0%	0%	0%	97%	0.0000	0.0000	0.0000
Gas (Propylene)	1,614	0.0029	8,760	100%	0%	0%	0%	97%	0.0000	0.0000	0.0000
Gas (Butane)	1,218	0.0029	8,760	100%	0%	0%	0%	97%	0.0000	0.0000	0.0000
Gas (Isobutane)	2,165	0.0029	8,760	100%	0%	0%	0%	97%	0.0000	0.0000	0.0000
Light Liquid (Methanol)	75	0.0005	8,760	100%	0%	0%	0%	97%	0.0000	0.0000	0.0000
Light Liquid (Natural Gasoline)	1,143	0.000463	8,760	100%	1%	0%	0%	97%	0.0000	0.0000	0.0000
Light Liquid (NGL)	2,350	0.000463	8,760	80%	1.2%	0%	0.19%	97%	0.0000	0.0003	0.0057
Water/Oil	123	0.000243	8,760	100%	0%	0%	0%	30%	0.0000	0.0000	0.0000
Heavy Liquid	2,146	0.0000165	8,760	100%	0%	0%	0%	30%	0.0000	0.0000	0.0000
Other [e]											
Gas (Natural Gas)	5	0.0194	8,760	7%	0%	4%	85%	97%	0.0005	0.0108	0.2279
Gas (Ethane)	51	0.2293	8,760	1%	0%	0%	1%	0%	0.0000	0.3269	6.8649
Gas (Propane)	77	0.2293	8,760	100%	0%	0%	0%	97%	0.0000	0.0000	0.0000
Gas (Propylene)	62	0.2293	8,760	100%	0%	0%	0%	97%			
Gas (Butane)	44	0.2293	8,760	100%	0%	0%	0%	97%	0.0000	0.0000	0.0000
Gas (Isobutane)	105	0.2293	8,760	100%	0%	0%	0%	97%	0.0000	0.0000	0.0000
Light Liquid (Methanol)	0	0.0035	8,760	100%	0%	0%	0%	0%	0.0000	0.0000	0.0000
Light Liquid (Natural Gasoline)	49	0.000287	8,760	100%	1%	0%	0%	97%	0.0000	0.0000	0.0000
Light Liquid (NGL)	74	0.0165	8,760	80%	1.2%	0%	0.19%	97%	0.0000	0.0003	0.0064
Water/Oil	5	0.0309	8,760	100%	0%	0%	0%	0%	0.0000	0.0000	0.0000
Heavy Liquid	51	0.0000683	8,760	100%	0%	0%	0%	0%	0.0000	0.0000	0.0000
								TOTAL:	**0.003**	**0.61**	**12.88**

[a] Fugitive Emission Factors and Reduction Credits are per TCEQ Technical Guidance Document for Equipment Leak Fugitives, dated October 2000. The emission factors are for total hydrocarbon. Reduction credit is for a 28LAER

[b] Hourly VOC emissions are calculated as follows:
(56 components) * (0.00992 lb/hr-component) * (100% VOC) * (100% - 97% reduction credit) = 0.0012 lb/hr

[c] Annual VOC emission rates are calculated as follows:
(0.0012 lb/hr) * (8760 hr/yr) / (2,000 lb/T) = 0.0051 T/yr

[d] Leakless pumps are not included in the pump count.

[e] "Other" includes diaphragms, dump arms, hatches, instruments, meters, and polished rods and are assumed to have same control efficiency as valves.

FRAC III AMINE UNIT POTENTIAL TO EMIT GREENHOUSE GASES

FRAC III PROJECT GHG PSD AIR PERMIT APPLICATION

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

				Amine Unit Uncontrolled Emissions [a] FIN: 3HT16.005					Thermal Oxidizer	EPN: 3SK25.002 Potential to Emit[b]	
	Carbon									Total	Combustion CO_2
Component	Atoms (Number)	MW (lb/lbmol)	HHV (Btu/lb)	Hourly (lb/hr)	Annual (T/yr)	Flow (scf/hr)	Flow (scf/yr)	Heating Value (MMBtu/hr)	DRE (%)	Annual (T/yr)	Annual (T/yr)
Nitrogen	0	28.0	0	1,749.84	7,664.30	23,685	207,483,528	0.00	0%	8,430.73	0
Carbon Dioxide	-	44.0	0	8,571.60	37,543.61	73,833	646,773,974	0.00	0%	41,297.97	0
Methane	1	16.0	23,861	2.16	9.46	51	448,205	0.06	99.9%	0.01	25.99
Ethane	2	30.1	22,304	253.92	1,112.17	3,197	28,007,460	6.23	99.9%	1.22	3248.27
Propane	3	44.1	21,646	137.35	601.60	1,180	10,340,457	3.27	99.9%	0.66	1798.91
i-Butane	4	58.1	21,242	37.74	165.30	246	2,156,597	0.88	99.9%	0.18	500.24
n-Butane	4	58.1	21,293	4.33	18.97	28	247,546	0.10	99.9%	0.02	57.42
i-Pentane	5	72.2	21,025	19.62	85.94	103	902,205	0.45	99.9%	0.09	261.59
n-Pentane	5	72.2	21,072	16.03	70.22	84	737,214	0.37	99.9%	0.08	213.75
n-Hexane	6	86.2	20,928	13.39	58.66	59	515,800	0.31	99.9%	0.06	179.47
Heptane	7	100.2	20,825	0.31	1.37	1	10,338	0.01	99.9%	0.00	4.20
Octane	8	114.2	20,747	0.11	0.47	<1	3,140	0.00	99.9%	0.00	1.46
Propene	3	42.1	20,833	53.03	232.26	477	4,181,831	1.22	99.9%	0.26	727.51
Total				**10,859.44**	**47,564.33**	**102,946**	**901,808,296**	**12.90**			**7,018.81**

Sample calculation CO_2 combustion (using methane):

CO_2 = (Amine Unit Methane Vent Rate, T/yr))*(TO Control eff.)*(No. of C, lbmol C/lbmol CH_4)*(44 lb CO_2/lbmol C)/(MW, lb CH_4/lbmol CH_4)

= (9.46 T/yr) * (99.9% Control Eff.) * (1 lbmol C/lbmol CH4) * (44 lb CO2/lbmol C) / (16.00 lb CH4/lbmol CH4)

= $\boxed{\text{25.99 T/yr}}$

N_2O = Fuel * HHV * 0.0001 (Eq. W-40, §98.233(z)(6))

Where:

N_2O = Annual emissions from combustion in kilograms

Fuel = volume combusted, scf/yr

HHV = High heat value of fuel, MMBtu/scf

NOTE: As an alternative to Fuel (scf/yr) * HHV (MMBtu/scf) to derive MMBtu/yr, the Amine Unit Vent (MMBtu/hr) * Annual Operating Hours (hr/yr) may be used to derive MMBtu/yr.

N_2O = (0.0001 kg N_2O/MMBtu) * (Amine Unit Vent, MMBtu/hr) * (8,760 hr/yr) / (0.4536 kg/lb) / (2,000 lb/T)

= (0.0001 kg N2O/MMBtu) * (12.90 MMBtu/hr)) * (8,760 hr/yr) / (0.4536 kg/lb) / (2,000 lb/T)

= $\boxed{\text{1.25E-02 T/yr}}$

Emission Summary:

EPN	FIN	Description	Uncombusted CO_2 (short T/yr)	Combustion CO_2 (short T/yr)	Uncombusted CH_4[a] (short T/yr)	Combustion N_2O (short T/yr)	CO_2e[b] (short T/yr)
3SK25.002	3HT16.005	FRAC III Thermal Oxidizer - Amine Vent	41,297.97	7,018.81	0.01	0.01	48,320.86

[a] Emissions were calculated using ProMax v. 3.0 simulation program. Inputs to the simulation program were a representative inlet gas analysis.

[b] CO_2e emissions are calculated as follows:

(41,297.97 T/yr Uncombusted CO2) + (7,018.81 T/yr Combustion CO2) + ((0.01 T/yr Methane) * 21) + ((0.0125 T/yr N2O) * 310) = 48,320.86 T/yr CO2e

FLARE FRAC III MSS POTENTIAL TO EMIT GREENHOUSE GASES

FRAC III PROJECT GHG PSD AIR PERMIT APPLICATION

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

FIN:	3MSS2
Total Flow (lb/event):	17,760
Event Duration (hr):	12
Number of Events/yr:	2

Component	Carbon Atoms (Number)	MW (lb/lbmol)	Concentration (wt%)	LHV (Btu/lb)	Uncontrolled Emissions [a] Hourly (lb/hr)	Uncontrolled Emissions [a] Annual (T/yr)	Flare DRE (%)	Heat Release [b] MMBtu/hr	Heat Release [b] MMBtu/yr	Total Potential to Emit [c] Annual (T/yr)	CO_2 Potential to Emit [d] Annual (T/yr)
Methane	1	16.0	2.5%	21,502	40.70	0.49	99%	0.87	20.79	0.005	1.33
Ethane	2	30.1	68.1%	20,416	1108.67	13.30	99%	22.41	537.80	0.13	38.51
Propane	3	44.1	21.5%	19,929	350.02	4.20	99%	6.91	165.74	0.04	12.45
i-Butane	4	58.1	2.5%	19,614	40.70	0.49	98%	0.78	18.78	0.01	1.45
n-Butane	4	58.1	3.9%	19,665	63.49	0.76	98%	1.22	29.37	0.02	2.26
i-Pentane	5	72.2	0.6%	19,451	9.77	0.12	98%	0.19	4.47	0.002	0.35
n-Pentane	5	72.2	0.5%	19,499	8.14	0.10	98%	0.16	3.73	0.002	0.29
n-Hexane	6	86.2	0.4%	19,391	6.51	0.08	98%	0.12	2.97	0.002	0.23
TOTAL:			**100.0%**		**1,628.0**	**19.54**		**32.65**	**783.64**	**0.21**	**56.87**

[a] An annual uncontrolled emission calculation example for methane follows:

(Total Flow, lb/event)*(Component wt%)*(events/yr)/(2,000 lb/ton)*(10% contingency factor) = (17,760 lb/event)*(2.5% wt%)*(2 events/yr)/(2,000 lb/ton)*1.1 = 0.49 T/yr CH_4

[b] An annual heat release calculation example for methane follows:

(LHV, Btu/lb)*(Emission, T/yr)*(DRE %)*(2,000 lb/ton) = (21,502/10^6 MMBtu/lb)*(0.49 T/yr)*(99% Flare DRE)*(2,000 lb/ton) = 20.79 MMBtu/hr

[c] CH$_4$ Emissions

$E_{a,CH4}$ (un-combusted) = V_a *(1-η)*X_{CH4} (Eq. W-19 in 98.233(n)(4))

Where:

$E_{a,CH4}$ (un-combusted) = Contribution of annual un-combusted CH4 emissions from flare in cubic feet.

V_a = Volume of vent gas cubic feet per year.

η = Fraction of gas combusted (default = 0.98).

X_{CH4} = Mole fraction of CH_4 in vent gas

Rather than using the molar flowrate (Va * X_{CH4}) entering the flare, the mass flowrate is substituted into the equation to calculate the mass flowrate. An example of the annual methane emission from the flare follows:

(Emission Rate, T/yr)*(1 - DRE %) = (0.49 T/yr)*(1- 99% Flare DRE) = 0.005 T/yr CH_4

FLARE FRAC III MSS POTENTIAL TO EMIT GREENHOUSE GASES

FRAC III PROJECT GHG PSD AIR PERMIT APPLICATION

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

[d] CO_2 Emissions

$E_{a,CO2}$ (combusted) = $\Sigma\ \eta * V_a * Y_j * R_j$ (Eq. W-21 in 98.233(n)(4))

Where:

$E_{a,CO2}$ (combusted) = Contribution of annual combusted CO_2 emissions from thermal oxidizer in cubic feet.
X_{CO2} = Mole fraction of CO_2 in vent gas
Y_j = Mole fraction of gas hydrocarbon constituents j.
R_j = Number of carbon atoms in the gas hydrocarbon constituent j.

Rather than using the molar flowrate (Va*Yj) entering the flare, the mass flowrate is substituted into the equation to calculate the mass flowrates from the flare. An example of the annual CO_2 emission rate from the combustion of methane follows:

(Emission Rate, T/yr) * (Flare DRE) * (No. of C, lbmol C/lbmol CH4) * (44 lb CO2/lbmol C) / (MW, lb CH4/lbmol CH4) = ((0.49 T/yr) * (99.0% Flare DRE) * (1 lbmol C/lbmol CH4) * (44 lb CO2/lbmol C) / (16 lb CH4/lbmol CH4)

1.33 T/yr

Combustion N_2O Emissions

N_2O = Fuel * HHV * 0.0001 (Eq. W-40, §98.233(z)(6))

Where:
N_2O = Annual emissions from combustion in kilograms
Fuel = volume combusted, scf/yr
HHV = High heat value of fuel, MMBtu/scf

NOTE: As an alternative to Fuel (scf/yr) * HHV (MMBtu/scf) to derive MMBtu/yr, the FlareVent Gas (MMBtu/hr) * Annual Operating Hours (hr/yr) may be used to derive MMBtu/yr.

N2O = (0.0001 kg N2O/MMBtu) * (Vent Gas, MMBtu/yr) / (0.4536 kg/lb) / (2,000 lb/T) = (0.0001 kg N2O/MMBtu) * (783.64 MMBtu/yr)) / (0.4536 kg/lb) / (2,000 lb/T)

= 8.64E-05 T/yr

FLARE FRAC III PIPING VENTS POTENTIAL TO EMIT GREENHOUSE GASES

FRAC III PROJECT GHG PSD AIR PERMIT APPLICATION

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

FIN:	3PV
Total Flow (lb/event):	180.80
Annual Hours (hr/yr):	8760

			Piping Vents				Uncontrolled Emissions From Pressure Relief Valve Equipment Leaks[b]						
					Uncontrolled Emissions[a]					Heat Release[c]		Total Potential to Emit[d]	CO_2 Potential to Emit[e]
Component	Carbon Atoms (Number)	MW (lb/lbmol)	Concentration (wt%)	LHV (Btu/lb)	Hourly (lb/hr)	Annual (T/yr)	Hourly (lb/hr)	Annual (T/yr)	Flare DRE (%)	MMBtu/hr	MMBtu/yr	Annual (T/yr)	Annual (T/yr)
Methane	1	16.0	0.0%	21,502	0.00	0.00	0.07	0.32	99%	0.002	13.55	0.003	0.87
Ethane	2	30.1	0.5%	20,416	0.08	0.35	1.05	4.61	99%	0.02	200.26	0.05	14.34
Propane	3	44.1	99.0%	19,929	22.91	100.35	0.19	0.84	99%	0.46	3,992.54	1.01	299.83
i-Butane	4	58.1	0.5%	19,614	0.15	0.67	0.72	3.14	98%	0.02	146.50	0.08	11.31
n-Butane	4	58.1	0.0%	19,665	0.00	0.00	0.78	3.41	98%	0.01	131.36	0.07	10.12
i-Pentane	5	72.2	0.0%	19,451	0.00	0.00	0.07	0.32	98%	0.001	12.20	0.01	0.96
n-Pentane	5	72.2	0.0%	19,499	0.00	0.00	0.06	0.28	98%	0.001	10.60	0.01	0.83
n-Hexane	6	86.2	0.0%	19,391	0.00	0.00	0.001	0.01	98%	0.00002	0.19	0.0001	0.02
Other Hexanes	6	86.2	0.0%	19,147	0.00	0.00	0.07	0.32	98%	0.001	12.10	0.01	0.97
Benzene	6	78.0	0.0%	18,000	0.00	0.00	0.01	0.03	98%	0.0001	1.19	0.001	0.11
TOTAL:			**100.0%**		**23.14**	**101.36**	**3.03**	**13.27**		**0.52**	**4,520.50**	**1.23**	**339.34**

[a] An annual uncontrolled emission calculation example for ethane follows:
(Total Flow, lb/event) * (Component wt%) / (379 scf/lb-mol) * (MW, lb/lb-mol) * (Annual Hours, hr/yr) / (2,000 lb/T) * (10% contingency factor) = (180.80 lb/event) * (0.5% wt%)/(379scf/lb-mol) * (30 lb/lb-mol) * (8,760 hr/yr) / (2,000 lb/T) * 1.1 =

0.35 T/yr C_2H_6

[b] Annual emissions are from FRAC III Plant Pressure Relief Valve Equipment Leaks to Flare Worksheet.

[c] An annual heat release calculation example for ethane follows:
(LHV, Btu/lb)*(Emission, T/yr)*(DRE %)*(2,000 lb/ton) = (20,416/10^6 MMBtu/lb)*((0.35 T/yr)+(4.61 T/yr))*(99% Flare DRE)*(2,000 lb/T) = 200.26 MMBtu/hr

[d] CH_4 Emissions

$E_{a,CH4}$ (un-combusted) = V_a *(1-η)*X_{CH4} (Eq. W-19 in 98.233(n)(4))

Where:

$E_{a,CH4}$ (un-combusted) = Contribution of annual un-combusted CH4 emissions from flare in cubic feet.
V_a = Volume of vent gas cubic feet per year.
η = Fraction of gas combusted (default = 0.98).
X_{CH4} = Mole fraction of CH_4 in vent gas

Rather than using the molar flowrate (Va * X_{CH4}) entering the flare, the mass flowrate is substituted into the equation to calculate the mass flowrate. An example of the annual methane emission from the flare follows:

(Emission Rate, T/yr)*(1 - DRE %) = ((0.00 T/yr)+(0.32 T/yr))*(1- 99% Flare DRE) = 0.003 T/yr CH_4

FLARE FRAC III PIPING VENTS POTENTIAL TO EMIT GREENHOUSE GASES

FRAC III PROJECT GHG PSD AIR PERMIT APPLICATION

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

[e] CO_2 Emissions

$E_{a,CO2}$ (combusted) = Σ η*V_a*Y_j*R_j (Eq. W-21 in 98.233(n)(4))

Where:

$E_{a,CO2}$ (combusted) = Contribution of annual combusted CO_2 emissions from thermal oxidizer in cubic feet.

X_{CO2} = Mole fraction of CO_2 in vent gas

Y_j = Mole fraction of gas hydrocarbon constituents j.

R_j = Number of carbon atoms in the gas hydrocarbon constituent j.

Rather than using the molar flowrate (Va*Yj) entering the flare, the mass flowrate is substituted into the equation to calculate the mass flowrates from the flare. An example of the annual CO_2 emission rate from the combustion of ethane follows:

(Emission rate, T/yr)*(Flare DRE)*(No. of C, lbmol C/lbmol C2H6)*(44 lb CO2/lbmol C)/(MW, lb C2H6/lbmol C2H6) = (((0.35 T/yr)+(4.61 T/yr))*(99.0% Flare DRE)*(2 lbmol C/lbmol C2H6)*(44 lb CO2/lbmol C)/(30 lb C2H6/lbmol C

$\boxed{14.34 \text{ T/yr}}$

Combustion N_2O Emissions

N_2O = Fuel * HHV * 0.0001 (Eq. W-40, §98.233(z)(6))

Where:

N_2O = Annual emissions from combustion in kilograms

Fuel = volume combusted, scf/yr

HHV = High heat value of fuel, MMBtu/scf

NOTE: As an alternative to Fuel (scf/yr) * HHV (MMBtu/scf) to derive MMBtu/yr, the FlareVent Gas (MMBtu/hr) * Annual Operating Hours (hr/yr) may be used to derive MMBtu/yr.

N_2O = (0.0001 kg N2O/MMBtu) * (Vent gas, MMBtu/yr) / (0.4536 kg/lb) / (2,000 lb/T) = (0.0001 kg N2O/MMBtu) * (4520.50 MMBtu/yr)) / (0.4536 kg/lb) / (2,000 lb/T)

= $\boxed{4.98E\text{-}04 \text{ T/yr}}$

FRAC III PLANT MISCELLANEOUS MAINTENANCE ACTIVITIES (EPN 3MSS1) POTENTIAL TO EMIT GREENHOUSE GASES

FRAC III PROJECT GHG PSD AIR PERMIT APPLICATION

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

	Equipment/Activity			
Description	**Replacement of Analyzer Filters/Screens**	**Filter/Meter Maintenance/Replacement**	**Spare Pump Startup**	**TOTAL**
Number of Events per Year	100	100	10	
Number of Events per hour	1	1	1	
Volume per Event, scf	1.70	0.10	4.20	
Stream Specific Gravity	0.6077	0.6077	0.6077	
Air MW, lb/mole	28.96	28.96	28.96	
Fuel Stream Density, lb/scf [a]	0.046	0.046	0.046	
Max CO_2 Percentage in Gas Stream, wt%	3.69%	3.69%	3.69%	
Max Methane Percentage in Gas Stream, wt%	90.64%	90.64%	90.64%	
CO_2 Annual Emission Rate (T/yr): [b]	0.0001	0.0000	0.0000	0.0002
Methane Annual Emission Rate (T/yr): [b]	0.004	0.0002	0.001	0.005
CO_2e Annual Emission Rate (T/yr): [b]	0.08	0.004	0.02	0.10

[a] Gas stream density is calculated as follows:

(28.96 lb/mole) / (379 scf/mole) * (0.6077) = 0.046 lb/scf

[b] Annual emission rates are calculated as follows:

(100 event/yr) * (1.70 scf/event) * (0.046 lb/scf) * (3.69 %) / (2,000 lb/T) = 0.00 T/yr

[c] Annual CO_2e emission rates are calculated as follows:

(0.0001 T/yr CO2) + ((0.004 T/yr Methane) * 21) = 0.08 T/yr CO2e

APPENDIX C
VENDOR EQUIPMENT SPECIFICATIONS

FRAC III PROJECT GHG PSD AIR PERMIT APPLICATION

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

Description **Page**

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TULSA HEATERS INC.

International Plaza
1350 S. Boulder; Suite 800
Tulsa, OK 74119 USA
Phone: (918) 582-9918
Fax: (918) 582-9916

March 11, 2013

S&B ENGINEERS and CONSTRUCTORS, Ltd.
ONE S&B DRIVE
1450 S&B Drive
Houston, TX 12345
United States of America

Attention: *Ms. Cristi Ray*

References: ***S&B's RFQ CE-1498-M0013 dated 5-March-2013***
THI's P13-8431 Rev.00

Dear Ms. Ray:

On behalf of the entire ***TULSA HEATERS INC***. *(* ***THI*** *) organization, it is my pleasure to present* ***THI*** *'s proposal for Two Direct Fired Heaters for Lone Star NGL in response to S&B's RFQ CE-1498-M0013 dated 5-March-2013.*

As requested in the inquiry, we wish to establish that " ***THI*** *'s quotation is in strict accordance with the subject inquiry, except as specifically set forth in Section 2.2 of this proposal".*

We sincerely appreciate the opportunity to compete for your business. As will become evident upon review of this proposal, ***THI*** *has invested considerable time in the development of this proposal in an effort to comply with your specifications, exceed your expectations, and to simply be "the best choice". Furthermore, we would welcome the opportunity to discuss this proposal with you and the Project Team in detail, so please contact either* ***THI*** *'s offices in Tulsa, OK (U.S.A.), or our local representative Mr. Scott Sanders of Heat Transfer Specialists of Texas , to initiate such a discussion.*

Best Regards,
TULSA HEATERS INC.

Allen D. Burris
Design / Sales Engineer

cc: *Mr. Scott Sanders; Heat Transfer Specialists of Texas*
Sales

ISO 9001 : 2000 CERTIFIED

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S&B for Lone Star
THI's P13-8431 Rev.00

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TULSA HEATERS' PROPOSAL

to

S&B Engineers and Constructors, Ltd.

for

Two Direct Fired Heaters

in support of the

Lone Star Frac III

Mont Belvieu

S&B's RFQ CE-1498-M0013 dated 5-March-2013

and

THI's P13-8431 Rev.00

11-Mar-13

TULSA HEATERS INC.
. . . combining experience & technology & quality management to provide your best choice . . .
corporate address: info@tulsaheaters.com
rfq / inquiry address: rfq@tulsaheaters.com
corporate website: www.tulsaheaters.com

ISO 9001 : 2000 CERTIFIED

1. INTRODUCTION

1.1 Executive Summary

*On behalf of the entire **TULSA HEATERS INC**. (**THI**) organization, it is my pleasure to present **THI**'s proposal for Two Direct Fired Heaters for Lone Star NGL in response to S&B's RFQ CE-1498-M0013 dated 5-March-2013.*

1.2 Introduction to TULSA HEATERS INC.

*As a worldwide OEM, **TULSA HEATERS INC**. (**THI**) strives to be the "best choice" for purchasers of fired heaters, waste heat recovery units, and complementary equipment by offering high quality customer services and products that address our **Customer**'s needs and expectations, at competitive prices. **THI**'s staff is able to consistently meet these goals via application of our collective 450+ years experience, **THI**'s state-of-the-art design tools, and adherence to **THI**'s ISO 9001:2000 registered Quality Management System (QMS).*

*Our extensive experience and proprietary software enables **THI** to provide turn-key product design services (process + combustion + mechanical + structural design + CADD) for ALL of the following products, systems and services. Rigorous adherence to **THI**'s ISO 9001:2000 registered QMS ensures that the design and subsequent fabrication are in accordance with contract documents.*

*Currently, **THI**'s product portfolio includes (but is not limited to) the following:*
• Horizontal Box Heaters; single or multi-cell w/ single or double fired coils,
• Horizontal Cabin Heaters; single or twin cell w/ single or double fired coils,
• Helical Coil Heaters; horizontal or vertical w/ single or double fired coils,
• Vertical Box Heaters; single or multi-cell w/ single or double fired coils,
• Vertical Cylindrical Heaters; single or twin cell w/single or double fired coils,
• Wicket/Arbor Heaters; single or multi-cell w/ single or double fired coils,
• Horizontal Heat Recovery Units; single or multi-feeds w/ fixed or removable coils,
• Vertical Heat Recovery Units; single or multi-service w/ fixed or removable coils,
• FCCU Start-Up Heaters; vertical or horizontal firing,

*Additionally, **THI**'s systems portfolio includes (but is not limited to) the following:*
• Process Manifolds Systems; Inlet &/or Outlet of any relative complexity,
• Burner Management Systems; gas or oil of any relative complexity,
• Burner Piping Systems; gas or oil of any relative complexity,
• Steam Systems; complete w/ coils, pumps, drum and interconnecting piping,
• Air Preheat Systems; FD, ID or BD systems w/ ADP avoidance provisions,
• DeNOx Systems; low & mid-temp SCR's,

*Additionally, since 1986, **THI**'s has maintained a Tech Services Group that provides the following "existing heater" support services:*
• Emergency Replacements of products (i.e., burndowns) regardless of the OEM,
• Burner Upgrades; experience and technology to provide 0.025 Lb/MMBTU performance,
• Existing Heater Retrofits/ Debottleneckings/ Revamps, and
• Existing Heater Engineering Studies/ Evaluations.

*In summary, **THI** has the responsiveness and flexibility of a small company, and the technical powers and financial strength of a large company. Given the chance, **THI** will provide a team that is rich with experience and committed to serving you, the **Customer**.*

2. BASIS of PROPOSAL

2.1 Applicable Documents

2.1.1 Inquiry Documents
This proposal is rigorously based on S&B's RFQ CE-1498-M0013 dated 5-March-2013 and all of its attachments (note the enclosed document listing: LIST 2.1). Furthermore, except as superseded by the inquiry specifications, ***THI****'s proposal is in accordance with the following industrial standards.*

2.1.2 ***THI****'s Design Standards*
Unless superseded by the ***Customer****'s inquiry specifications,* ***THI****'s proposal is based on the application of ISO 13705 and the following industry standards to the extent that they apply to general service fired heaters and waste heat recovery modules.*

• API	Std 530, Std 560, RP 531M, RP 535, RP536 RP 550 and RP 556
• AISC	Manual of Steel Construction
• ANSI/ASCE	7-02
• ASME	B16.5, B16.9, B16.11, B31.1, B31.3, B36.10, Boiler & Pressure Vessel Code, Sections I through IX
• ASTM	A193, A194, A-297, A-351, A384, A385, C64, C155, C332, E186,
• CSA	B51
• ICBO	Uniform Building Code
• ISO	13704 & 13705
• CNBC	Canadian National Building Code

2.1.3 ***THI****'s Manufacturing Standards*

• ASTM	Tubes*:	A53, A106, A161, A200, A213, A271, A312, A333, A335, A376, A608, B163, B167, B407 and B423
	* All heater tubes will be seamless, unless such tubulars are not commercially available (and same will be ERW w/ 100% RT).	
	Fittings:	A216, A217, A234, A351, A403, A420, B366
	Forgings:	A105, A182, A350, B564
	Supports:	A216, A217, A240, A283, A297, A447, A560, E165, E433, E446
	Refractory	C27, C155, C401, C612
	L&P's:	A36, A123, A143, A153, A384, A385, A572, A588, A786
	Casing:	A36, A514, A529, A572, A852
	Stiffeners:	A36, A242, A529, A572, A588, A852, A913
	Structure:	A36, A242, A529, A572, A588, A913, A992
• AWS	D1.1 Structural Welding Code	
• CSA	W47.1, W59	
• SSPC	SP-3, SP-5, SP-6, SP-10	

2. BASIS of PROPOSAL

List 2.1

S&B RFQ CI-1498-M0013 - Request for Quotation
S&B Terms & Conditions - Dated 15-Feb-2013
S&B VIR Forms
S&B Inspection Matrix
Lone Star NGL Project AML
300-HR 15.001 - Hot Oil Heater Data Sheets
300-HR 15.002 - Regen Heater Data Sheets
300-SE29.055 - SCR Data Sheets
PIP ELSPS01 - Electrical Requirements for Packaged Equipment
PIP STS05120 Structrual and Miscellaneous Steel Fabrication
PIP VECV1001 - Vessel Design Criteria
PIP VEFV1100 - Vessel / S&T Heat Exchanger Standard Details
PIP VESV1002 - Vessel Fabrication Specification

2.2 Clarifications and / or Exceptions

2.2.1 C&E's to Industry Standards
*This proposal is based on **THI** 's clarifications and exceptions to API STANDARD 560 Fourth Edition, which are provided in TABLE 2.2 for your review and acceptance.*

2.2.2 C&E's to Inquiry Documents
*This proposal is based on the following comments and exceptions to the inquiry documents, which were received by **THI** prior to the date of this proposal, and are provided for your review and acceptance. No other documents were considered in **THI** 's preparation of this proposal, regardless of reference or inference.*

<u>*S&B Terms & Conditions - Dated 15-Feb-2013*</u>

Clause 17 Exception - THI shall not be liable for, nor shall quoted prices include any federal, state, foreign or local sales, excise, use or other taxes associated with the sale of goods hereunder and Purchaser hereby indemnifies Seller for any and all loss, cost, expense or liability arising from the imposition or attempted imposition of any such tax.

Clause 24 Exception - Buyer may not cancel the order for late delivery. Compensation due to Buyer because of late delivery shall be limited to liquidated damages specific to delivery. Such liquidated damages, if applicable, shall be discussed and agreed on a contract specific basis.

<u>*S&B VIR Forms*</u>

General Clarification - These have been filled in, and are included as Table 3.3 of this proposal.

<u>*PIP STS05120 Structrual and Miscellaneous Steel Fabrication*</u>

General Clarification - Certain aspects of the proposed stairtower do not meet all of PIP requirements. The proposed stairtowers are identical in concept to the previous Lone Star project.

<u>*PIP VECV1001 - Vessel Design Criteria*</u>
<u>*PIP VEFV1100 - Vessel / S&T Heat Exchanger Standard Details*</u>
<u>*PIP VESV1002 - Vessel Fabrication Specification*</u>

General Clarification - The only equipment for which these standards will apply is certain componenet(s) of the SCR package. As of this proposal, the SCR manufacturer has not reviewed the above documents. We may provide comments at a later date.

<u>*S&B RFQ CI-1498-M0013 - Request for Quotation*</u>
<u>*S&B Inspection Matrix*</u>
<u>*Lone Star NGL Project AML*</u>
<u>*300-HR 15.001 - Hot Oil Heater Data Sheets*</u>
<u>*300-HR 15.002 - Regen Heater Data Sheets*</u>
<u>*300-SE29.055 - SCR Data Sheets*</u>
<u>*PIP ELSPS01 - Electrical Requirements for Packaged Equipment*</u>

THI accepts the above specifications without clarification or comment.

Owner:	**Lone Star NGL**	*Owner Ref.:*	**300-HR-001** **Jan-00**	*Ftnt & Rev*
Purchaser:	S&B Engineers and Constructors, Ltd.	*Purch. Ref.:*	C-1498	
Manufacturer:	***TULSA HEATERS INC.***	***THI*** *Ref.:*	***P13-8431A***	
Heater Type:	*Vertical Cylindrical, Single Cell*	*Location:*	*Mont Belvieu*	

CLARIFICATIONS & EXCEPTIONS TO API STANDARD 560, FOURTH EDITION

5 ***Proposals (documentation)***

5.3.3.a *Structural steel and stack fabrication drawings will not be submitted for review unless requested by Purchaser.*

5.3.3.c *Tube support drawings are proprietary, and will not be issued for information or approval. Purchaser is welcome to review any/all applicable support drawings while visiting THI's Tulsa, OK (USA) offices.*

7 ***Tubes***

7.1.2 *Unless specifically stated to the contrary,* ***THI****'s offering provides a tube Errosion Allowance of 0.00 mm (0.00 in).*

8 ***Headers (ie, fittings)***

8.1.4 *Unless specifically stated to the contrary,* ***THI****'s proposal provides a header Errosion Allowance of 0.00 mm (0.00 in).*

9 ***Piping, Terminals and Manifolds***

9.2 *Except when specifically stated to the contrary,* ***THI****'s proposal provides for 100% of the terminal loadings OR the movements of Tables 6 & 7, respectively, but NOT multiples of same. Loadings &/or movements in excess of Tables 6 &/or 7 must be documented in Purchaser's inquiry for* ***THI****'s incorporation into the coil design (ie, increasing the proposed wall thickness of terminal tubes & fittings). Purchaser's failure to do so could result in* ***THI****'s rejection of "excessive" loadings &/or movements. The same limitations apply to manifold terminals (eg, Tables 8 & 9).*

12 ***Structures and Appurtenances***

12.4.1 ***THI****'s proposed platforms - both quantity and size - are set forth on* ***THI****'s heater data sheets (incl. in Section 6).*

13 ***Stacks, Ducts and Breeching***

13.5.7 *Unless stated to the contrary,* ***THI****'s proposal does NOT account for the buffeting effects of "close structures".*

13.5.8 *Unless stated to the contrary,* ***THI****'s proposal does NOT account for the buffeting effects of "close stacks or vessels".*

13.5.9 *Unless stated to the contrary,* ***THI****'s proposal does NOT account for the upwind "stacks or vessels".*

The design requirements of items 13.5.7, 13.5.8 and 13.5.9 can be incorporated into ***THI****'s scope, providing that the project scope and jobsite conditions have been adequately defined by the Customer.*

14 ***Burners and Auxiliary Equipment***

14.1.2 ***THI****'s burner offerings may / may not comply with all local and national statutes and regulations.*

14.1.10 ***THI****'s proposed pilot offerings are the Burner OEM's standard pilots, which may/may not comply with this paragraph.*

14.1.13 ***THI****'s proposed materials are those of the Burner OEM proposals in Section 10; reference same for clarification.*

14.2.2 ***THI****'s proposed sootblower offerings may/may not comply with this paragraph.*

14.4.4 *Unless stated to the contrary,* ***THI****'s proposal provides conventional sleeve bearings on all uptake damper shafts.*

14.4.5 *In the interest of safety,* ***THI****'s Engineering Standards require stack dampers to FAIL OPEN (FO).*

14.4.7 *Unless stated to the contrary,* ***THI****'s proposal does NOT provide a grade mounted "position control mechanism".*

15 ***Instrument and Auxiliary Connections***

15.5 *Unless specifically stated to the contrary,* ***THI****'s proposal does NOT provide platform access to every casing connection.*

16 ***Shop Fabrication and Field Erection***

16.6.8 *Addition: Unless specifically stated to the contrary,* ***THI****'s proposal does NOT provide external coatings of any form or type on any pressure parts (including tubes, fittings and flanges), regardless of coil material or location.*

16.6.11 *Unless specifically stated to the contrary,* ***THI****'s proposal does NOT provide for the stenciling of the words "DO NOT WELD" on any pressure parts that have been stress relieved or thermally stabilized, regardless of location.*

17 ***Inspection, Examination and Testing***

17.4.6 *Typical support lug welds on fabricated convection-tube intermediate supports are single bevel with fillet, and as such, these welds can not be radiographed. Unless stated to the contrary,* ***THI****'s proposal does NOT provide for same.*

End of ***THI****'s comments to API Standard 560 / ISO 13705, Fourth Edition.*

Rev: 01	*8-Oct-08*	*Edited/Condensed into a "Customer Friendly" Format*	*SLS*	*ENG*	*MPL*
Rev: 00	*21-Jun-08*	*Issued to capture significant changes of the Fourth Edition*	*SLS*	*ENG*	*MPL*
revision	*date*	*description*	*by*	*chk'd*	*appv'd*

Lone Star NGL

TABLE 2.2: C&E's to STD 560, 4rth ED.

STANDARD CLARIFICATIONS & EXCEPTIONS

P13-8431A -TBL2.2- Rev: 01 ***Page 1 of 1***

3. SCOPE of SUPPLY

3.1 Activities

This proposal provides for the following major activities:

- *Process Design (combustion + thermal + hydraulic + draft),*
- *Mechanical Design (coil wall + terminal loads + refractory),*
- *Structural Design (with RISA),*
- *Project Management,*
- *General Arrangement Drawings and Documentation,*
- *Fabrication (Detail) Drawings and Documentation,*
- *Component & Materials Procurement,*
- *Shop Fabrication and Module Assembly,*
- *Expediting,*
- *Quality Assurance/Quality Control,*
- *Document Control,*
- *Shipping Preparation,*
- *Shipping to Site/Port (optional),*
- *Site Supervision (optional), and*
- *Commissioning and Start-up (optional).*

3.2 Materials & Services

The basic intent of this proposal is to provide the core scope of supply that has been developed for THI's projects J11-733 / 734 and J12-768 / 769 (S&B's projects C-1469 & 1480). The heaters proposed here have been specifically designed for this application, however all relevant materials and services that were provided in the referenced projects are included here. See THI's List2 3.2.1 & 3.2.2 for details.

Furthermore, realizing that the proposed custom engineered heater has not been fully integrated ***into the Customer****'s process unit design,* ***THI*** *offers to provide future material and engineering changes as set forth in section 8.3. Please refer to subsection 8.3 for details.*

3.3 Documentation

The above activities will typically yield the following relevant documentation:

- *Data Sheets; fired heaters, burners, fans, etc.,*
- *Calculations; draft, settings, coil wall, stack frequency, structural, etc.*
- *Performance Curves; burners, fans, etc.,*
- *General Arrangement Drawings; casing, structure, refractory, coil, components,*
- *Foundation Loading Diagram; wind, seismic, snow and load combinations,*
- *Fabrication Drawings; all fabricated components except coil,*
- *Procedures; performance test, NDE, welding, PWHT, and erection procedures,*
- *Final Data Books; collection of all historically important data, and*
- *Test and NDE Records.*

S&B's VIR forms have been completed, and are attached as Table 3.3.

Owner:	**Lone Star NGL**	*Owner Ref.:* **300-HR-001**	*Ftnt*
Purchaser:	S&B Engineers and Constructors, Ltd.	*Purch. Ref.:* C-1498	*Rev.00* *&*
Manufacturer:	***TULSA HEATERS INC.***	***THI*** *Ref.:* ***P13-8431A***	*11-Mar-13* *Rev*
Heater Type:	*Vertical Cylindrical, Single Cell*	*Location:* Mont Belvieu	

Products & Services	***Design THI***	***Design Others***	***Supply THI***	***Supply Others***	***Erection THI***	***Erection Others***	***Comments***
I. Major Components / Systems Overview:							
1. Fired Heater(s)	xx		xx			xx	
2. Secondary Heat Recovery Sys.		xx		xx		xx	*Not Applicable*
3. Flue Gas Ht. Recovery (APH) System		xx		xx			*Not Applicable*
4. Flue Gas DeNOx (SCR) System	xx		xx				*Integrally nested in convection section*
5. Flue Gas DeSOx System		xx		xx			*Not Applicable*
6. Burner Management System	xx		xx			xx	*as clarified in Section 6*
7. Local Instrumentation		xx		xx		xx	*No process instrumentation in THI's scope*
8. Burner Piping (Burners to Heater Edge)	xx		xx			xx	*including flex hoses*
9. Utility Piping		xx		xx		xx	*None in THI's Scope*
10. Process Piping		xx		xx		xx	*None in THI's Scope*
11. Process Manifolds	xx		xx			xx	*inlet & outlet manifolds included*
12. Piers & Related Civil Work		xx		xx		xx	*None in THI's Scope; by Others*
II. Fired Heater - Primary Systems/Modules:							
1. Radiant Section Casing & Structure	xx		xx			xx	*Shop Fab'd; clarified in Section 6*
2. Radiant Refractory & Supports	xx		xx			xx	*Shop Installed; clarified in Section 6*
3. Radiant Internal & External Coatings	xx		xx			xx	*Shop Applied; clarified in Section 6*
4. Radiant Coil(s) w/ Supports & Guides	xx		xx			xx	*Shop Installed; clarified in Section 6*
5. Convection Casing & Structure	xx		xx			xx	*Shop Fab'd; clarified in Section 6*
6. Convection Refractory & Supports	xx		xx			xx	*Shop Installed; clarified in Section 6*
7. Convection Internal & External Coatings	xx		xx			xx	*Shop Applied; clarified in Section 6*
8. Convection Coil(s) w/ Supports & Guides	xx		xx			xx	*Shop Installed; clarified in Section 6*
9. Uptakes & Stack Casing & Structure	xx		xx			xx	*Shop Fab'd; clarified in Section 6*
10. Uptakes & Stack Refractory & Supports	xx		xx			xx	*Shop Installed; clarified in Section 6*
11. Modularization of Above Components	xx		xx			xx	*as clarified in Section 4*
12.							
III. Secondary Heat Recovery System:							*None in THI's Scope*
IV. Flue Gas Heat Recovery System:							*None in THI's Scope*
V. Flue Gas DeNOx System:							
1. Ammonia Flow Control Unit (AFCU)	xx		xx			xx	*Field Installed; clarified in Section 6*
2. Ammonia Injectioin Grid (AIG)	xx		xx			xx	*Field Installed; clarified in Section 6*
3. Reactor w/ Catalyst	xx		xx			xx	*Field Installed; clarified in Section 6*
4. Interconnecting Piping (AFCU to AIG)		xx		xx		xx	*None in THI's Scope*
5. 10,000 gal aqueous ammonia tank	xx		xx			xx	*One quote currently for both trains*
6. Ammonia uploading facility	xx		xx			xx	*Field Installed; clarified in Section 6*
7. Ammonia pump skid, spare, instrumentation	xx		xx			xx	*Field Installed; clarified in Section 6*
VI. Flue Gas DeSOx System:							*None in THI's Scope*
VII. Burner Management System & Instrumentation:							
1. Fuel / Pilot Gas Skids	xx		xx			xx	*Field Installed; clarified in Section 6*
2. Local Control/ SD Panel	xx		xx			xx	*Field Installed; clarified in Section 6*
3. Local Instrumentation, per P&ID	xx		xx			xx	*Field Installed; clarified in Section 6*
4. Ignition / Detection Package	xx		xx			xx	*Ionization rod - pilot / UV scanner - main*

Lone Star NGL

TABLE 3.2.1: MATERIALS & SERVICES

PROPOSED SCOPE of SUPPLY

P13-8431A-TBL3.2-Rev.00 ***Page 1 of 2***

rfq@tulsaheaters.com ◆ info@tulsaheaters.com ◆ (918) 582-9916 Fax ◆ TULSA HEATERS INC. ◆ 1350 South Boulder Ste 800 ◆ Tulsa, OK 74119 ◆ www.tulsaheaters.com

Owner:	**Lone Star NGL**	*Owner Ref.:* **300-HR-001**		*Ftnt*
Purchaser:	S&B Engineers and Constructors, Ltd.	*Purch. Ref.:* C-1498	*Rev.00*	*&*
Manufacturer:	***TULSA HEATERS INC.***	***THI*** *Ref.:* ***P13-8431A***	*11-Mar-13*	*Rev*
Heater Type:	*Vertical Cylindrical, Single Cell*	*Location:* Mont Belvieu		

Products & Services	***Design***		***Supply***		***Erection***		***Comments***
	THI	***Others***	***THI***	***Others***	***THI***	***Others***	
VIII. Miscellaneous Engineered Components:							
1. Burners, w/Tile & Continuous Pilot	xx		xx			xx	*Field Installed; clarified in Section 6*
2. Sootblowers w/ Local Control Panel		xx		xx		xx	*None in THI's Scope*
3. Stack Damper, with Operator		xx		xx		xx	*None in THI's Scope*
4. Coil Connections (T, P & TSTC's)	xx		xx			xx	*Field Installed; clarified in Section 6*
5. Casing Connections (T, P & Comp.)	xx		xx			xx	*Field Installed; clarified in Section 6*
6. Ladders & Platforms, galvanized	xx		xx			xx	*Field Installed; clarified in Section 6*
7. Field Erection "Spares"	xx		xx			xx	*Field Installed; clarified in Section 6*
8. ID Fan Assembly c/w vibration dampner	xx		xx			xx	*Field Installed; clarified in Section 6*
9. VFD Package for ID fan	xx		xx			xx	*Field Installed; clarified in Section 6*
10. Process Flow Balancing Stations	xx		xx			xx	*Orifice plates by Others*
11.							
IX. Complementary Services:							
1. Kick-Off Meeting @ Customer's Offices	xx		xx				*as required*
2. Pre-FAB Meeting @ THI's Offices	xx		xx				*as required*
3. Burner Test @ OEM's @ Shop	xx		xx				*Included; clarified in Section 6*
4. Refractory Dryout @ Shop		xx		xx			*None in THI's Scope*
5. QA per Contract & THI's QMS	xx		xx				*Included; clarified in Section 5*
6. Domestic Shipping Prep	xx		xx			xx	*Included; clarified in Section 5*
7. Freight / Insurance to Jobsite		xx		xx		xx	*None in THI's Scope*
X. Documentation Services:							
1. Documentation Package for Above	xx		xx		xx	xx	*as proposed in* ***Table 3.3***

TABLE 3.2.1: MATERIALS & SERVICES

PROPOSED SCOPE of SUPPLY

P13-8431A-TBL3.2-Rev.00 ***Page 2 of 2***

rfq@tulsaheaters.com ◆ info@tulsaheaters.com ◆ (918) 582-9916 Fax ◆ TULSA HEATERS INC. ◆ 1350 South Boulder Ste 800 ◆ Tulsa, OK 74119 ◆ www.tulsaheaters.com

Owner:	**Lone Star NGL**	*Owner Ref.:*	**300-HR-002**	*Ftnt*
Purchaser:	S&B Engineers and Constructors, Ltd.	*Purch. Ref.:*	C-1498	*Rev.00* *&*
Manufacturer:	***TULSA HEATERS INC.***	***THI** Ref.:*	***P12-8431B***	*11-Mar-13* *Rev*
Heater Type:	*Vertical Cylindrical, Single Cell*	*Location:*	Mont Belvieu, TX	

Products & Services	***Design***		***Supply***		***Erection***		***Comments***
	THI	***Others***	***THI***	***Others***	***THI***	***Others***	
I. Major Components / Systems Overview:							
1. Fired Heater(s)	xx		xx			xx	*as clarified in Section 6*
2. Secondary Heat Recovery Sys.		xx		xx		xx	*None in THI's Scope*
3. Flue Gas Ht. Recovery (APH) System		xx		xx			*None in THI's Scope*
4. Flue Gas DeNOx (SCR) System		xx		xx			*None in THI's Scope*
5. Flue Gas DeSOx System		xx		xx			*None in THI's Scope*
6. Burner Management System	xx		xx			xx	*as clarified in Section 6*
7. Local Instrumentation		xx		xx		xx	*No process instrumentation in THI's scope*
8. Burner Piping (Burners to Heater Edge)	xx		xx			xx	*including flex hoses*
9. Utility Piping		xx		xx		xx	*None in THI's Scope*
10. Process Piping		xx		xx		xx	*None in THI's Scope*
11. Process Manifolds	xx		xx			xx	*inlet & outlet manifolds included*
12. Piers & Related Civil Work		xx		xx		xx	*None in THI's Scope; by Others*
II. Fired Heater - Primary Systems/Modules:							
1. Radiant Section Casing & Structure	xx		xx			xx	*Shop Fab'd; clarified in Section 6*
2. Radiant Refractory & Supports	xx		xx			xx	*Shop Installed; clarified in Section 6*
3. Radiant Internal & External Coatings	xx		xx			xx	*Shop Applied; clarified in Section 6*
4. Radiant Coil(s) w/ Supports & Guides	xx		xx			xx	*Shop Installed; clarified in Section 6*
5. Convection Casing & Structure	xx		xx			xx	*Shop Fab'd; clarified in Section 6*
6. Convection Refractory & Supports	xx		xx			xx	*Shop Installed; clarified in Section 6*
7. Convection Internal & External Coatings	xx		xx			xx	*Shop Applied; clarified in Section 6*
8. Convection Coil(s) w/ Supports & Guides	xx		xx			xx	*Shop Installed; clarified in Section 6*
9. Uptakes & Stack Casing & Structure	xx		xx			xx	*Shop Fab'd; clarified in Section 6*
10. Uptakes & Stack Refractory & Supports	xx		xx			xx	*Shop Installed; clarified in Section 6*
11. Flue Gas Duct - Connecting to Hot Oil Heater	xx		xx			xx	*Shop Fab'd; clarified in Section 6*
12. Modularization of Above Components	xx		xx			xx	*as clarified in Section 4*
III. Secondary Heat Recovery System:							*None in THI's Scope*
IV. Flue Gas Heat Recovery System:							*None in THI's Scope*
V. Flue Gas DeNOx System:	xx		xx			xx	*Integral to the Hot Oil Heater*
VI. Flue Gas DeSOx System:							*None in THI's Scope*
VII. Burner Management System & Instrumentation:							
1. Fuel / Pilot Gas Skids	xx		xx			xx	*Field Installed; clarified in Section 6*
2. Local Control/ SD Panel	xx		xx			xx	*Field Installed; clarified in Section 6*
3. Local Instrumentation, per P&ID	xx		xx			xx	*Field Installed; clarified in Section 6*
4. Ignition / Detection Package	xx		xx			xx	*Ionization rod - pilot / UV scanner - main*
VIII. Miscellaneous Engineered Components:							
1. Burners, w/Tile & Continuous Pilot	xx		xx			xx	*Field Installed; clarified in Section 6*
2. Sootblowers w/ Local Control Panel		xx		xx		xx	*None in THI's Scope*
3. Flue Gas Damper, with Operator	xx		xx			xx	*Field Installed; clarified in Section 6*
4. Coil Connections (T, P & TSTC's)	xx		xx			xx	*Field Installed; clarified in Section 6*
5. Casing Connections (T, P & Comp.)	xx		xx			xx	*Field Installed; clarified in Section 6*
6. Ladders & Platforms, galvanized	xx		xx			xx	*Field Installed; clarified in Section 6*
7. Field Erection "Spares"	xx		xx			xx	*Field Installed; clarified in Section 6*

Lone Star NGL

TABLE 3.2.2: MATERIALS & SERVICES

PROPOSED SCOPE of SUPPLY

P12-8431B-TBL3.2-Rev.00 ***Page 1 of 2***

rfq@tulsaheaters.com ◆ info@tulsaheaters.com ◆ (918) 582-9916 Fax ◆ TULSA HEATERS INC. ◆ 1350 South Boulder Ste 800 ◆ Tulsa, OK 74119 ◆ www.tulsaheaters.com

Owner:	**Lone Star NGL**	*Owner Ref.:*	**300-HR-002**		*Ftnt*
Purchaser:	S&B Engineers and Constructors, Ltd.	*Purch. Ref.:*	C-1498	*Rev.00*	*&*
Manufacturer:	***TULSA HEATERS INC.***	***THI** Ref.:*	***P12-8431B***	*11-Mar-13*	*Rev*
Heater Type:	*Vertical Cylindrical, Single Cell*	*Location:*	Mont Belvieu, TX		

Products & Services	***Design***		***Supply***		***Erection***		***Comments***
	THI	***Others***	***THI***	***Others***	***THI***	***Others***	
IX. Complementary Services:							
1. Kick-Off Meeting @ Customer's Offices	xx		xx				*as required*
2. Pre-FAB Meeting @ THI's Offices	xx		xx				*as required*
3. Burner Test @ OEM's @ Shop	xx		xx				*Included; clarified in Section 6*
4. Refractory Dryout @ Shop		xx		xx			*None in THI's Scope*
5. QA per Contract & THI's QMS	xx		xx				*Included; clarified in Section 5*
6. Domestic Shipping Prep	xx		xx			xx	*Included; clarified in Section 5*
7. Freight / Insurance to Jobsite		xx		xx		xx	*None in THI's Scope*
X. Documentation Services:							
1. Documentation Package for Above	xx		xx		xx	xx	*as proposed in **Table 3.3***

rfq@tulsaheaters.com ◆ info@tulsaheaters.com ◆ (918) 582-9916 Fax ◆ TULSA HEATERS INC. ◆ 1350 South Boulder Ste 800 ◆ Tulsa, OK 74119 ◆ www.tulsaheaters.com

THI 's P13-8431 Table 3.3 Rev. 00

S & B ENGINEERS and CONSTRUCTORS, LTD.

VENDOR INFORMATION REQUIREMENT FORM

INDUCED DRAFT FAN

(#) PKG/TAG NUMBER(S):
300-SE29.016

PAGE: 1 OF 1
S&B JOB NO: C1498
INQUIRY NO: M0013
REQ. NO: M0013
REQ.ENGR: M. ROBAU
DATE: 03/05/13

VENDOR INFORMATION REQUIREMENTS

VENDOR SHALL FURNISH ELECTRONIC COPIES OF DOCUMENTS

CODE*	TYPE	SEQ	DESCRIPTION	NO. WEEKS A.R.O. FOR SUBMITTAL — Vendor To Complete W/Quote	DUE DATE — S & B Complete At Award Meeting
			DOCUMENTS FOR REFERENCE INFORMATION		
R	SCHD	100	Shop Fab/Production Sched (Including long delivery and 3rd party info)	8	
			DOCUMENTS FOR DETAIL DESIGN ENGINEERING		
A,C	DO	200	Dimension & Outline Drawing Including:	7	
A,C	MOD	201	Motor Outline Drawing w/Electrical Connections	11	
A,C	MED	202	Motor Electrical Data (Data Sheet, Thermal and Starting Curves)	11	
			DOCUMENTS FOR INSTALLATION, OPERATION & MAINTENANCE		
R	OIM	300	Installation, Operation & Maintenance Manual	AT SHIPMENT	
R	SP$	301	Start-up Spare Parts W/Unit Prices	AT SHIPMENT	
R	SP$2	302	Spare Parts Required - 2 Years Operation W/Prices	AT SHIPMENT	

NOTES: 1. Vendor shall provide P.O. Number and Tag Number on all documentation submitted.
2. Identical items may be represented on a common document, provided that Tag Items for all pieces included are clearly shown.
3. Quotation will not be considered complete unless this form is completed and signed by Vendor.

*CODE:
A - For Approval PRIOR to Fabrication
B - For Approval (Don't HOLD Fabrication)
C - Certified
P - Proposal: Submit with Quote
R - For Reference Only
S - Send At Or Prior To Ship Date

VENDOR: Tulsa Heaters
DATE: 11-March-2013
SIGNATURE: [signature]

VIRF NUMBER: M0013*BLCN

S & B ENGINEERS and CONSTRUCTORS, LTD.

VENDOR INFORMATION REQUIREMENT FORM

API-560 DIRECT FIRED HEATER

(#)PKG/TAG NUMBER(S):
300-HR15.001
300-HR15.002

PAGE: 1 OF 2
S&B JOB NO: C1498
INQUIRY NO: M0013
REQ. NO: M0013
REQ.ENGR: M. ROBAU
DATE: 03/05/13

V E N D O R   I N F O R M A T I O N   R E Q U I R E M E N T S

VENDOR SHALL FURNISH ELECTRONIC COPIES OF DOCUMENTS

CODE*	TYPE	SEQ	DESCRIPTION	NO. WEEKS A.R.O. FOR SUBMITTAL Vendor To Complete W/Quote	DUE DATE S & B Complete At Award Meeting
			DOCUMENTS FOR REFERENCE INFORMATION		
R	SCHD	100	Shop Fab/Production Sched (Including long delivery and 3rd party info)	8	
R	MISC	101	Unpriced Purchase Orders	12	
			DOCUMENTS FOR DETAIL DESIGN ENGINEERING		
A,C	DS	200	Data Sheet		
A,C	DO	201	Dimension & Outline Drawing per API Standard 560 Sect 5.3.1	6	
A,C	FND	202	Foundation Loading Diagram per API Standard 560 Sect 5.3.2	6	
A,C	DC	203	Design Calculations for Heater and Stack including wind loads, allowable	6	
			nozzle loads and moments, lifting lugs, and tailing lugs	6	
A,C	DC	204	ASME/API 530 Design Calculations	6	
B,C	DET	205	Shop Fabrication Details	16	
			Details shall include but not be limited to the below listed items and other		
			information as required for detailed review of the design of the exchanger.		
			Convection Section Details		
			Stack Details		
			Lifting Lugs and Locations		
			Insulation/Refractory Anchor Details		
			Name Plate Drawing		
			Bill of Materials		
A,C	DET	206	Ladder and Platform Details at each elevation and structural members	18	
A,C	DET	207	Burner Assembly, Details, Piping, Curves and Pilot Drawings	7	
B,C	DET	208	Air Duct / Arrangement Drawings	5	
A,C	WP	209	Weld Procedure Specification (WPS) & Procedure Qualification Record (PQR)	10	
A,C	WM	210	Weld Map	20	
A,C	TFP	211	Test/Fabrication Procedure	10	
A,C	ITP	212	Inspection & Test Plan	10	
B,C	DET	213	Ceramic Fiber & Castable Refractory Information including Design Calcs.	10	
B,C	TR	214	Installation, Dry Out, & Test Procedure for Refractory and Insulation	10	
B,C	DET	215	Erection Drawing with Erection Sequence	16	
B,C	DET	216	Tubeskin Thermocouple Details	8	
B,C	DS	217	ISA Data Sheets for Instruments	12	
			DOCUMENTS FOR INSTALLATION, OPERATION & MAINTENANCE		

R   OIM   300 Installation, Operation & Maintenance Manual

NOTES: 1. Vendor shall provide P.O. Number and Tag Number on all documentation submitted.
2. Identical items may be represented on a common document, provided that Tag Items for all pieces included are clearly shown.
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*CODE: A - For Approval PRIOR to Fabrication
B - For Approval(Don't HOLD Fabrication)
C - Certified
P - Proposal: Submit with Quote
R - For Reference Only
S - Send At Or Prior To Ship Date

VENDOR: Tulsa Heaters
DATE: 11-March-2013
SIGNATURE: [signature]

VIRF NUMBER: M0013*HEST

S & B ENGINEERS and CONSTRUCTORS, LTD.

VENDOR INFORMATION REQUIREMENT FORM

API-560 DIRECT FIRED HEATER

(#) PKG/TAG NUMBER(S):
300-HR15.001
300-HR15.002

PAGE: 2 OF 2
S&B JOB NO: C1498
INQUIRY NO: M0013
REQ. NO: M0013
REQ.ENGR: M. ROBAU
DATE: 03/05/13

VENDOR INFORMATION REQUIREMENTS

VENDOR SHALL FURNISH ELECTRONIC COPIES OF DOCUMENTS

CODE*	TYPE	SEQ	DESCRIPTION	NO. WEEKS A.R.O. FOR SUBMITTAL (Vendor To Complete W/Quote)	DUE DATE (S & B Complete At Award Meeting)
R	NP	301	Name Plate Digital Photograph or Rubbing	4 AS	
R	TR	302	Hydrostatic Test Report	4 AS	
R	MT	303	Mill Tests Report	2 AS	
R	TR	304	NDT Test Report	2 AS	
R	SP$	305	Start-up Spare Parts W/Unit Prices	2 AS	
R	SP$2	306	Spare Parts Required - 2 Years Operation W/Prices	2 AS	

NOTES: 1. Vendor shall provide P.O. Number and Tag Number on all documentation submitted.
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R - For Reference Only
S - Send At Or Prior To Ship Date

VIRF NUMBER: M0013*HEST

S & B ENGINEERS and CONSTRUCTORS, LTD.

VENDOR INFORMATION REQUIREMENT FORM

BURNER MANAGEMENT SYSTEM

(#) PKG/TAG NUMBER(S):
300-SE29.061
300-SE29.062

PAGE: 1 OF 1
S&B JOB NO: C1498
INQUIRY NO: M0013
REQ. NO: M0013
REQ.ENGR: M. ROBAU
DATE: 03/05/13

V E N D O R   I N F O R M A T I O N   R E Q U I R E M E N T S

VENDOR SHALL FURNISH ELECTRONIC COPIES OF DOCUMENTS

CODE*	TYPE	SEQ	DESCRIPTION	NO. WEEKS A.R.O. FOR SUBMITTAL Vendor To Complete W/Quote	DUE DATE S & B Complete At Award Meeting
			DOCUMENTS FOR REFERENCE INFORMATION		
R	SCHD	100	Shop Fab/Production Sched (Including long delivery and 3rd party info)	8	
			DOCUMENTS FOR DETAIL DESIGN ENGINEERING		
A,C	DO	200	Fuel Skid Piping Plan and Elevation	18	
B	DET	201	Fuel Skid Structural Steel Drawing	18	
A	CP	202	Control Panel Drawing with Bill of Materials	18	
A	NPD	203	Name Plate Drawing	12	
A,C	SCHE	204	Junction Box Layout	18	
A,C	SCHE	205	Schematic Wiring Diagram	18	
A,C	IS	206	ISA Instrument Data Sheets	12	
R	CCS	207	Instrument Catalog Cut Sheet	18	
A,C	WP	208	Weld Procedure Specification (WPS) & Procedure Qualification Record (PQR)	18	
A,C	ITP	209	Inspection & Test Plan	18	
A,C	MISC	210	Cause & Effect Diagram	12	
A	OM	211	Sequence of Operations	18	
			DOCUMENTS FOR INSTALLATION, OPERATION & MAINTENANCE		
R	OIM	300	Installation, Operation & Maintenance Manual	AT SHIPMENT	
R	NP	301	Name Plate Digital Photograph or Rubbing	AT SHIPMENT	
R	TR	302	Hydrostatic Test Report	AT SHIPMENT	
R	MT	303	Mill Tests Report	AT SHIPMENT	
R	SP$	304	Start-up Spare Parts W/Unit Prices	AT SHIPMENT	
R	SP$2	305	Spare Parts Required - 2 Years Operation W/Prices	AT SHIPMENT	
R	MISC	306	PLC Logic Printout	AT SHIPMENT	

NOTES: 1. Vendor shall provide P.O. Number and Tag Number on all documentation submitted.
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VENDOR: Tulsa Heaters
DATE: 11-March-2013
SIGNATURE: [signature]

VIRF NUMBER: M0013*HEST1

S & B ENGINEERS and CONSTRUCTORS, LTD.

VENDOR INFORMATION REQUIREMENT FORM

AMMONIA TANK

(#) PKG/TAG NUMBER(S):
300-PV17.057

PAGE: 1 OF 1
S&B JOB NO: C1498
INQUIRY NO: M0013
REQ. NO: M0013
REQ.ENGR: M. ROBAU
DATE: 03/05/13

VENDOR INFORMATION REQUIREMENTS

VENDOR SHALL FURNISH ELECTRONIC COPIES OF DOCUMENTS

CODE*	TYPE	SEQ	DESCRIPTION	NO. WEEKS A.R.O. FOR SUBMITTAL Vendor To Complete W/Quote	DUE DATE S & B Complete At Award Meeting
			DOCUMENTS FOR REFERENCE INFORMATION		
R	SCHD	100	Shop Fab/Production Sched (Including long delivery and 3rd party info)	7	
			DOCUMENTS FOR DETAIL DESIGN ENGINEERING		
A,C	DO*	200	Dimension & Outline Drawing Including:	7	
			Design Data		
A,R	NPD	201	Name Plate Drawing	7	
B,R	DET	202	Shop Fabrication Details	7	
B	DET	203	Ladder and Platform Details	19	
B,R	BM	204	Bill of Materials	19	
A,C	DC	205	Design Calculations	8	
			1. Code Calculations		
			2. External (Nozzles, Wind load, Earthquake) Calculations		
			3. Lifting Lugs, Tailing Lugs, etc.		
A,C	WP	206	Weld Procedure Specification and PQR	12	
A,C	WM	207	Weld Map	12	
A,R	ITP	208	Inspection & Test Plan	12	
B,R	TFP	209	Test/Fabrication Procedure	12	
			DOCUMENTS FOR INSTALLATION, OPERATION & MAINTENANCE		
C	ASME	300	ASME Code Data Reports (Including U-1)	AT SHIPMENT	
R	NP	301	Name Plate Digital Photograph or Rubbing	AT SHIPMENT	
R	TR	302	Hydrostatic Strip Chart Record	AT SHIPMENT	
R	TR	303	NDT Test Report	AT SHIPMENT	
R	MT	304	Mill Tests Report	AT SHIPMENT	

NOTES: 1. Vendor shall provide P.O. Number and Tag Number on all documentation submitted.
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R - For Reference Only
S - Send At Or Prior To Ship Date

VENDOR: Tulsa Heaters
DATE: 11-March-2013
SIGNATURE: [signature]

VIRF NUMBER: M0013*PV

S & B ENGINEERS and CONSTRUCTORS, LTD.

VENDOR INFORMATION REQUIREMENT FORM

AMMONIA FLOW CONTROL SKID

(#)PKG/TAG NUMBER(S):
300-SE29.054
300-HT16.034
300-SE29.063A
300-SE29.063B

PAGE: 1 OF 1
S&B JOB NO: C1498
INQUIRY NO: M0013
REQ. NO: M0013
REQ.ENGR: M. ROBAU
DATE: 03/05/13

V E N D O R   I N F O R M A T I O N   R E Q U I R E M E N T S

VENDOR SHALL FURNISH ELECTRONIC COPIES OF DOCUMENTS

CODE*	TYPE	SEQ	DESCRIPTION	NO. WEEKS A.R.O. FOR SUBMITTAL Vendor To Complete W/Quote	DUE DATE S & B Complete At Award Meeting
			DOCUMENTS FOR REFERENCE INFORMATION		
R	SCHD	100	Shop Fab/Production Sched (Including long delivery and 3rd party info)	10	
			DOCUMENTS FOR DETAIL DESIGN ENGINEERING		
A,C	DO*	200	Dimension & Outline Drawing Skid	10	
A,C	FD	201	Flow Diagram (P&ID)	10	
A,C	DO	202	Dimension & Outline Drawing Vaporizer	17	
A,C	DO	203	Dimension & Outline Drawing Dilution Air Fans	14	
A,C	DS	204	Fan Data Sheet Including Performance Curve	10	
A	MOD	205	Motor Outline Drawing w/Electrical Connections	10	
A	MED	206	Motor Electrical Data w/Thermal and Starting Curves	10	
A,R	NPD	207	Name Plate Drawing	10	
A	CP	208	Control Panel Drawing Including the Bill of Materials	14	
R	INX	209	Instrument Index/List	10	
A,C	IS	210	ISA Instrument Data Sheets	10	
A,C	WD	211	Wiring Diagram	12	
A,C	IL	212	Control Logic Diagram	14	
A,C	IS	213	Control Logic Summary	14	
A,C	WP	214	Weld Procedure Specification and PQR	14	
A,C	WM	215	Weld Map	14	
A,R	ITP	216	Inspection & Test Plan	14	
B,R	TFP	217	Test/Fabrication Procedure	14	
			DOCUMENTS FOR INSTALLATION, OPERATION & MAINTENANCE		
R	OIM	300	Installation, Operation & Maintenance Manual	AT SHIPMENT	
R	NP	301	Name Plate Digital Photograph or Rubbing	AT SHIPMENT	
R	TR	302	Hydrotest Report	AT SHIPMENT	
R	TR	303	NDT Test Report	AT SHIPMENT	
R	MT	304	Mill Tests Report	AT SHIPMENT	

NOTES: 1. Vendor shall provide P.O. Number and Tag Number on all documentation submitted.
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*CODE: A - For Approval PRIOR to Fabrication
B - For Approval(Don't HOLD Fabrication)
C - Certified
P - Proposal: Submit with Quote
R - For Reference Only
S - Send At Or Prior To Ship Date

VENDOR: Tulsa Heaters
DATE: 11-March-2013
SIGNATURE: Allen B—

VIRF NUMBER: M0013*PV1

S & B ENGINEERS and CONSTRUCTORS, LTD.

VENDOR INFORMATION REQUIREMENT FORM

AMMONIA PUMP SKID & TRUCK UNLOADING SKID

(#) PKG/TAG NUMBER(S):
300-SE29.059
300-PM18.087A

PAGE: 1 OF 1
S&B JOB NO: C1498
INQUIRY NO: M0013
REQ. NO: M0013
REQ.ENGR: M. ROBAU
DATE: 03/05/13

VENDOR INFORMATION REQUIREMENTS

VENDOR SHALL FURNISH ELECTRONIC COPIES OF DOCUMENTS

CODE*	TYPE	SEQ	DESCRIPTION	NO. WEEKS A.R.O. FOR SUBMITTAL (Vendor To Complete W/Quote)	DUE DATE (S & B Complete At Award Meeting)
			DOCUMENTS FOR DETAIL DESIGN ENGINEERING		
A,C	DO	200	Dimension & Outline Drawing for Ammonia Pump Skid and Truck Unloading Skid	12	
A,C	DO	201	Dimension & Outline Drawing Pump	12	
A,C	FD	202	Flow Diagram (P&ID)	7	
R	INX	203	Instrument Index/List	12	
A,C	IS	204	ISA Instrument Data Sheets	12	
A,C	WD	205	Wiring Diagram	12	
A,C	WD	206	Junction Box Layout	12	
A,C	WP	207	Weld Procedure Specification and PQR	12	
A,R	ITP	208	Inspection & Test Plan	12	
B,R	TFP	209	Test/Fabrication Procedure	12	
			DOCUMENTS FOR INSTALLATION, OPERATION & MAINTENANCE		
R	OIM	300	Installation, Operation & Maintenance Manual	AT SHIPMENT	
R	TR	301	Hydrostest Report	AT SHIPMENT	
R	TR	302	NDT Test Report	AT SHIPMENT	
R	MT	303	Mill Tests Report	AT SHIPMENT	

NOTES: 1. Vendor shall provide P.O. Number and Tag Number on all documentation submitted.
2. Identical items may be represented on a common document, provided that Tag Items for all pieces included are clearly shown.
3. Quotation will not be considered complete unless this form is completed and signed by Vendor.

*CODE: A - For Approval PRIOR to Fabrication
B - For Approval(Don't HOLD Fabrication)
C - Certified
P - Proposal: Submit with Quote
R - For Reference Only
S - Send At Or Prior To Ship Date

VENDOR: Tulsa Heaters
DATE: 13 - March - 2013
SIGNATURE: [signature]

VIRF NUMBER: M0013*PV2

S & B ENGINEERS and CONSTRUCTORS, LTD.

VENDOR INFORMATION REQUIREMENT FORM

SCR FRAMEWORK

(#) PKG/TAG NUMBER(S):
300-SE29.055

PAGE: 1 OF 1
S&B JOB NO: C1498
INQUIRY NO: M0013
REQ. NO: M0013
REQ.ENGR: M. ROBAU
DATE: 03/05/13

V E N D O R   I N F O R M A T I O N   R E Q U I R E M E N T S

VENDOR SHALL FURNISH ELECTRONIC COPIES OF DOCUMENTS

CODE*	TYPE	SEQ	D E S C R I P T I O N	NO. WEEKS A.R.O. FOR SUBMITTAL — Vendor To Complete W/Quote	D U E D A T E — S & B Complete At Award Meeting
			DOCUMENTS FOR DETAIL DESIGN ENGINEERING		
A,C	DO	200	Dimension & Outline Drawing Ammonia Injection Grid	12	
A,C	DO	201	Dimension & Outline Drawing Catalyst Support	12	
A,C	WP	202	Weld Procedure Specification and PQR	12	
A,R	ITP	203	Inspection & Test Plan	12	
			DOCUMENTS FOR INSTALLATION, OPERATION & MAINTENANCE		
R	OIM	300	Installation Instructions	AT SHIPMENT	
R	MT	301	Mill Tests Report	AT SHIPMENT	

NOTES: 1. Vendor shall provide P.O. Number and Tag Number on all documentation submitted.
2. Identical items may be represented on a common document, provided that Tag Items for all pieces included are clearly shown.
3. Quotation will not be considered complete unless this form is completed and signed by Vendor.

*CODE: A - For Approval PRIOR to Fabrication
B - For Approval(Don't HOLD Fabrication)
C - Certified
P - Proposal: Submit with Quote
R - For Reference Only
S - Send At Or Prior To Ship Date

VENDOR: Tulsa Heaters
DATE: 13-March-2013
SIGNATURE: [signature]

VIRF NUMBER: M0013*PVIN

4. DEGREE of SHOP FABRICATION / ASSEMBLY

4.1 Standard Manufacturing Practices

*It is **THI**'s Standard Manufacturing Practice to maximize shop fabrication and assembly (i.e., modularization). This practice consistently yields the "lowest installed cost" for most types of general service fired heaters. Following is an overview of the typical provisions that **THI**'s Standard Manufacturing Practices typically provide:*

4.1.1 General Practices

- *Module designs will minimize field erection time and labor by minimizing the number of modules. In other words, the size and weight of the module(s) will be maximized, up to the Purchaser's Shipping Constraints, thus minimizing the number of modules.*
- *Module designs will minimize pressure part welding at the jobsite.*
- *Modules designs will provide lifting lugs suitable for safe handling and erection. Spreader beams, however, are not included in our base offer unless expressly stated.*
- *Horizontal heater radiant modules that exceed the allowable shipping width will feature "removable center panels", such that the complimentary sidewalls can be bolted together and shipped as one module. Once the module arrives at the jobsite, the "removable center panels" are reinstalled between the sidewalls to achieve the design heater width.*
- *Unless specifically stated to the contrary, ALL pressure parts - including any/all external components - are offered bare . . . without coatings (external and/or internal) and/or metal diffusion treatments (external and/or internal) of any kind,*
- *Unless specifically stated to the contrary, ALL manifolds of 26.00"OD and larger are offered in ERW w/ 100% RT construction (seamless is not commonly available).*

4.1.2 Radiant Section Module(s)

- *Casing joints of cylindrical heaters will be spot RT'd and evaluated per AWS D1.1,*
- *Casing joints of flat panel heaters will be spot RT'd and evaluated per AISC,*
- *Casing/Structure will be shop fabricated in transportable modules, complete with the internal and external coatings specified on the job specific GA/Fab Drawings,*
- *Refractory systems, as specified on GA Drawings, will be shop installed, and*
- *Single fired serpentine coil subassemblies will be fabricated, HAZ's heat treated (as appropriate), NDE'd, and stabbed/installed into each module at the FabShop,*
- *Double fired serpentine coil subassemblies will be fabricated, HAZ's heat treated (as appropriate), NDE'd, and prepped for shipping (panels field install by Erector),*
- *Wicket coil subassemblies will be fabricated, HAZ's heat treated (as appropriate), NDE'd, and prepped for shipping (subassemblies field install by Erector),*
- *Low NOx natural draft burners with individual plenums will be used whenever spatially possible (smaller vertical heaters will have common burner plenums).*

4.1.3 Convection Section Module(s)

- *Casing joints of ALL convection sections will be spot RT'd and evaluated per AISC,*
- *Casing/Structure will be shop fabricated in transportable modules, complete with the internal and external coatings specified on the job specific GA/Fab Drawings,*
- *Refractory systems, as specified on GA Drawings, will be shop installed,*
- *Coil supports will be shop installed, and*
- *Coil will be finned/studded (as appropriate), hairpinned, stabbed, welded, HAZ's heat treated (as appropriate), and NDE'd.*

*4.1 **Standard Modularization Practices** (concluded)*

4.1.4 Stacks/Ducts

- *Casing joints will be spot radiographed and evaluated per AWS D1.1,*
- *Casing/Structure will be shop fabricated in transportable modules, complete with internal and external coatings specified on the job specific GA/Fab Drawings,*
- *Refractory systems, as specified on GA Drawings, will be shop installed, and*
- *Damper operators, as appropriate, will be shop installed (onto the damper shaft), test stroked, removed from the shaft and shipped in a container / crate.*

4.1.5 APH/ DeNOx/ DeSOx Systems

- *Engineered components will be "shipped loose" for field assembly/ installation,*
- *Engineered components will be "shipped loose" for field assembly/ installation,*
- *Interconnecting ducting will be shop fabricated, refractory lined and internally &/or externally coated as specified by the GA Dwgs, and*
- *Structural towers will be fabricated, coated, and disassembled for field assembly.*

4.1.6 Ladders & Platforms

- *Ladders, platforms and stairs will be fabricated, test assembled (not to heater), galvanized and shipped in transportable bundles ready for field assembly.*
- *Clips will be shop installed (if L&P's are located in a timely manner).*

4.1.7 Miscellaneous

All engineered components and smaller items will be properly prepped for shipping:

- *burners, actuators and small engineered components, and*
- *sufficient refractory & bolting hardware for field erection.*

4.2 Standard Materials Sourcing Practices

*As a worldwide OEM, **TULSA HEATERS INC**. (**THI**) materials sourcing practices vary slightly "country-by-country" to reflect each country's available materials.*

- *Tubulars are sourced world-wide; although we strive to rigorously comply with all inquiry documents (i.e., approved manufacturer's lists), the fluid tubular supply industry may "force" **THI** to incorporate materials from alternative QMS approved sources into its proposed offering. Upon request, **THI** will willingly disclose the primary pressure part sources that are the basis of its proposal.*
- *Coil finning materials will be sourced by one of **THI**'s QMS approved shops.*
- *Cast supports will be sourced from a QMS approved foundry.*
- *Modules fabricated outside the U.S.A. will have locally sourced structural steel, plate, and refractories (as available). The balance of components will be from QMS approved sources. (typically, from U.S.A, Japan &/or W.Europe).*
- *Modules fabricated in the U.S.A. will have maximum domestic content. However, we reserve the right to use imported materials on an "as needed" basis in order to comply with our contractual commitments.*
- *Erection Spare Parts include 5% spare firebrick, 5% spare refractory materials (for field joint completion), 10% spare bolting hardware.*
- *Manufacturer's Standard Coatings will be provided on all engineered items (e.g., fans, burners, dampers, operators).*

5. PROJECT EXECUTION

5.1 Project Management Plan

THI *proposes to manage this project from its offices in Tulsa, OK (U.S.A.). A dedicated* ***THI*** *Project Team would be established immediately upon receipt of an order, and would remain intact throughout the duration of the project.* ***THI*** *'s Project Team would have the technical expertise and experience to address this project's needs, and typically consists of the following members:*

1. *Project Manager*
2. *Project Engineer*
3. *Project Designer*
4. *Project Checker*
5. *Structural Engineer*
6. *Process Engineer*
7. *Quality Engineer*
8. *Purchasing Manager*
9. *Production Manager*
10. *Project Inspector*
11. *Project Expeditor*

5.1.1 Project Manager

THI *'s Project Manager would have overall responsibility for the proper execution of all work to be performed. He would be the primary communicator with the Customer's Team, and would communicate regularly with the Customer's Project Manager to insure that all Contract requirements are fulfilled. His primary responsibilities would include:*

- *Review all PO documents to develop an understanding of PO requirements,*
- *Direct and coordinate all phases of the work associated with the design, procurement, fabrication, testing and erection (if applicable) of the project,*
- *Meet the project's safety, performance, schedule, and budget objectives,*
- *Development and submission of project schedules and progress reports and,*
- *Comply with all contractual obligations in a timely, safe and professional manner.*

5.1.2 Project Engineer

THI *'s Project Engineer would be responsible for the timely design, review and/or issuance of Bills of Materials (to Purchasing) and facilitating the resolution of any technical conflicts.*

5.1.3 Project Designer

THI *'s Project Designer would be responsible for the timely generation of technically correct General Arrangement Drawings (GA's) and supporting project documents. His primary responsibilities would include:*

- *Develop heater worksheets and preliminary design sketches,*
- *Develop technically correct "preliminary" GA's and Bills of Materials (BoM's),*
- *Integrate the Project Team's comments into Rev.00 GA's and BoM's, and*
- *Compile/format GA's for delivery to Customer in a timely manner.*

5.1.4 Project Checker

THI *'s Project Checker would be responsible for the timely detailed review of all General Arrangement Drawings (GA's) and supporting project documents*

5.1 Project Management Plan *(concluded)*

5.1.5 Structural Engineer

THI's Structural Engineer would be responsible for the structural design of all products, subsystems and platforms. His primary responsibilities would include the following:*

- *Generate 3D computer structural models and document foundation loads,*
- *Size all structural members and develop weights of every component,*
- *Perform pipe flex analysis of manifolds and coil sections,*
- *Determine allowable loads and movements of terminals,*

5.1.6 Process Engineer

THI's Process Engineer would be responsible for the process design of all products and subsystems. His primary responsibilities to this project include the review of inquiry/contract documents, develop a technically correct and efficient process design for the specific application, document changes during the proposal phase, and provide technical support to the Team for the duration of the project.*

5.1.7 Quality Engineer

THI's Quality Engineer would be responsible for the timely generation of technically correct QIP's (i.e., Quality Inspection Plans, Quality Test Plans, etc.) and to provide technical support to our Fabricators' in their development of fabrication procedures.*

5.1.8 Purchasing Manager

THI's Purchasing Manager would be responsible for the procurement of all materials and services, from issue of the initial order to completion. He would be responsible for the procurement plan, all order correspondence with vendors, and the cost & time efficient procurement of technically acceptable materials and services.*

5.1.9 Production Manager

THI's Production Manager would be responsible for the scheduling of work and materials with Fabricators, and to facilitate the timely transmittal of contract documents to said Fabricators. His primary responsibilities would include:*

- *Develop & maintain summary schedules that reflect current Fabricator activity,*
- *Coordinate contract document flow to and from our Fabricators,*
- *Support the Fabricator's efforts with "whatever it takes",*

5.1.10 Project Inspector

THI's Project Inspector would be responsible for the proper and timely execution of the Project's QA plan (i.e., the product's rigorous conformance with the Contract). At times, in order to meet contract schedule(s),* ***THI*** *may supplement our staff inspectors with qualified third party inspectors (e.g., C.K. INSPECTION of Tulsa).*

5.1.11 Project Expeditor

THI's Project Expeditor would be responsible for the tracking and expediting the project's orders of materials, components, and fabricated modules.*

5.2 Quality Management System

5.2.1 Goals

*The goals of **THI**'s Quality Management System (QMS) are the following:*

- *to provide high quality products that meet and/or exceed the Customer's contract, requirements, and*
- *to continuously improve our company procedures and processes that will yield improvements in product or systems quality.*

***THI**'s QMS is ISO 9001:2000 registered by AQSR International (a copy of **THI**'s certificate is included in the Appendices). In short, **THI**'s QMS is a customer focused quality system designed to consistently yield technically acceptable products (i.e., per the Customer's specifications) while also yielding manufacturing efficiency improvements.*

*Because **THI**'s ISO registered QMS applies to all new and all retrofit projects, any potential customer can rest assured that his new product or major retrofit will be designed, manufactured and NDE'd in accordance with his project specifications and **THI**'s QMS policies.*

5.2.2 QMS Policy

THI's QMS Policy is simple and customer focused:

STRIVE TO BE THE PREFERRED SOURCE
FOR
FIRED HEATERS & WASTE HEAT RECOVERY UNITS
THROUGH OUR TOTAL COMMITMENT
TO
QUALITY AND CUSTOMER SERVICE.

5.2.3 QMS Standards

*This policy objective is based on the application of the following **THI** Standard Practices:*

- *Use only proven process and mechanical design programs and practices,*
- *Use a project management system to coordinate and schedule the activities of Engineering, Procurement, Production and Quality Control,*
- *Use a document control system that assures the issue of all pertinent documents and data to each individual, or department, essential to the satisfactory completion of the project, and the prompt removal of all obsolete documents and data from use,*
- *Maintain a current list of Approved Sub-Vendors, that have consistently demonstrated the capability to supply materials and services in accordance with the job requirements, and*
- *Develop and implement a quality inspection plan (QIP) for each and every job, new or retrofit, to identify the inspection and documentation requirements.*

6. TECHNICAL

6.1 Revision Table

6.2 Overview of Hot Oil Heaters - 300-HR-001; THI's P13-8431A

6.2.1 Technical Discussion

*The proposed heater is a single cell vertical cylindrical type with a serpentine coil configuration that satisfies the inquiry document requirements. In accordance with these documents, **THI** 's base offer for this heater provides the following performance and features:*

Process Design
- *Total process duty of 156.6 MMBtu/hr during Design operations,*
- *Process pressure drop of 33.1 psi for Design operations,*
- *Calculated thermal efficiency of 90.2% during Design operations,*

Combustion Design
- *ULTRA Low NOx burners (total of 12) providing at least 5:1 turndown,*
- *Nested SCR reactor,*
- *Flue gas emissions that comply with the rfq expectations (NOx of 0.01 lb/MMBtu),*
- *One top mounted ID fan w/ VFD, designed to provide -0.4 inH2O of draft at the arch at design,*

Mechanical Design
- *Process Coils and Process Coil Supports per the rfq specifications,*
- *Radiant floor of stiffened 0.25 in CS plate; per data sheets & TABLE 3.2,*
- *Radiant sidewalls of stiffened 0.25 in CS plate; per data sheets & TABLE 3.2,*
- *Radiant arch of stiffened 0.25 in CS plate; per data sheets & TABLE 3.2,*
- *Radiant structure of typical CS shapes; per data sheets & TABLE 3.2,*
- *Convection sidewalls of stiffened 0.1875 in CS plate; per data sheets & TABLE 3.2,*
- *Convection tubesheets of 0.5 in CS plate; per data sheets & TABLE 3.2,*
- *Convection structure of typical CS shapes; per data sheets & TABLE 3.2,*
- *Self-supporting stack of 0.25 in (minimum) thick CS plate, per data sheets & TABLE 3.2,*
- *External coating(s) are per data sheets & TABLE 3.2,*
- *Internal coating is included per data sheets & TABLE 3.2,*

6.2.2 Fired Heater Data Sheets; Single Cell, Vertical Cylindrical
6.2.3 Mass, Energy & Momentum Data Sheet
6.2.4 Sketch; Single Cell, Vertical Cylindrical Heater Elevation

Owner:	**Lone Star NGL**	*Owner Ref.:*	**300-HR-001**
Purchaser:	S&B Engineers and Constructors, Ltd.		**300-HR-002**
Manufacturer:	***TULSA HEATERS INC.***	*Purchaser Ref.:*	C-1498
		THI *Ref.:*	***P12-8314***
		Unit No:	*Train 3*
		Location:	*Mont Belvieu*

Revision	*Date*	*Description*	*By*	*Chk'd*	*Appv'd*
Rev.00	*11-Mar-13*	*Issued w/ Initial Proposal*	*ADB*	*TLC*	*VPS*

Lone Star NGL

PROPOSAL REVISION TABLE

AMERICAN ENGINEERING SYSTEM of UNITS

P12-8314- REVtbl - Rev.00 ***Pg 1 of 1***

Owner:	**Lone Star NGL**		Owner Ref.:	**300-HR-001**
Purchaser:	S&B Engineers and Constructors, Ltd.		Purchaser Ref.:	C-1498
Manufacturer:	***TULSA HEATERS INC.***		***THI*** *Ref.:*	***P13-8431A***
Service:	Hot Oil		Unit No:	Train 3
Number:	One		Location:	Mont Belvieu
Process Duty:	**156.60**	**MMBTU/ hr**	Heater Type:	***Vertical Cylindrical, Single Cell***
Total Duty:	**156.60**	**MMBTU/ hr**		***w/ Integral Convection Section***

Ftnt & Rev

PROCESS DESIGN CONDITIONS

Heater Section	- - -	**RADIANT**	**CONVECTION**		**TOTAL**
Operating Case	- - -	**Case A: Design -**	**Hot Oil Only**		
Service	- - -	Hot Oil	Hot Oil		
Heat Absorption	MMBTU/ hr	**96.57**	**60.03**		**156.60**
Process Fluid	- - -	Therminol 55	Therminol 55		
Process Mass Flow Rate, Total	Lb/ hr	2,497,300	2,497,300		
Process Bulk Velocity (allow. / calc.)	ft/ s	- - - / 13	- - - / 9		
Process Mass Velocity (min./ calc.)	Lb/ s ft2	- - - / 624	- - - / 432		
Coking Allowance (dP calcs)	in				
Pressure Drop, Clean (allow. / calc.)	psi	< ------- **35** /	**33** ------- >		
Pressure Drop, Fouled (allow. / calc.)	psi	< ------- /	------- >		
Average Heat Flux (allowable)	BTU/ hr ft2	0			
Average Heat Flux (calculated)	BTU/ hr ft2	**13,570**			
Maximum Heat Flux (allowable)	BTU/ hr ft2				
Maximum Heat Flux (calculated)	BTU/ hr ft2	20,360	21,430		
Fouling Factor, Internal	hr ft2 °F/ BTU	0.001	0.001		
Corrosion or Erosion Characteristics	- - -				
Max. Film Temperature (allow. / calc.)	°F	550 / 488	550 / 463		
Inlet Conditions:					
Temperature	°F	**331**	**288.7**		
Pressure	psig	**107**	**118**		
Mass Flow Rate, Liquid	Lb/ hr		2,497,300		
Mass Flow Rate, Vapor	Lb/ hr		0		
Weight Percent, Liquid / Vapor	wt%		100% / 0%		
Density, Liquid / Vapor	Lb/ ft3		49.20 /		
Molecular Weight, Liquid / Vapor	Lb/ Lbmole		/		
Viscosity, Liquid / Vapor	cp		1.418 /		
Specific Heat, Liquid / Vapor	BTU/ Lb °F		0.561 /		
Thermal Conductivity, Liquid/Vapor	BTU/hr ft °F		0.066 /		
Surface Tension, Liquid	dyne/ cm				
Outlet Conditions:					
Temperature	°F	**400**	**331**		
Pressure	psig	**85.0**	**107**		
Mass Flow Rate, Liquid	Lb/ hr	2,497,300			
Mass Flow Rate, Vapor	Lb/ hr	0			
Weight Percent, Liquid / Vapor	wt%	100% / 0%			
Density, Liquid / Vapor	Lb/ ft3	46.50 /			
Molecular Weight, Liquid / Vapor	Lb/ Lbmole	/			
Viscosity, Liquid / Vapor	cp	0.718 /			
Specific Heat, Liquid / Vapor	BTU/ Lb °F	0.612 /			
Thermal Conductivity, Liquid/Vapor	BTU/hr ft °F	0.062 /			
Surface Tension, Liquid	dyne/ cm				

revision	date	description	by	chk'd	appv'd

FIRED HEATER DATA SHEET

AMERICAN ENGINEERING SYSTEM of UNITS

P13-8431A- HTRds - Rev.00 **Pg 1 of 13**

Owner:	**Lone Star NGL**	*Owner Ref.:*	**300-HR-001**	*Ftnt*
Purchaser:	S&B Engineers and Constructors, Ltd.	*Purch. Ref.:*	C-1498	*&*
Manufacturer:	***TULSA HEATERS INC.***	***THI** Ref.:*	***P13-8431A***	*Rev*
Service:	*Hot Oil*	*Unit No:*	*Train 3*	
Number:	*One*	*Location:*	*Mont Belvieu*	
Process Duty:	***156.60 MMBTU/ hr***	*Heater Type:*	***Vertical Cylindrical, Single Cell***	
Total Duty:	***156.60 MMBTU/ hr***		***w/ Integral Convection Section***	

ADDITIONAL PROCESS OPERATING CONDITIONS

Heater Section	*- - -*	***RADIANT***	***CONVECTION***		***TOTAL***
Operating Case	*- - -*	***Case B: Design Hot Oil + Regen***			
Service	*- - -*	*Hot Oil*	*Hot Oil*		
Heat Absorption	*MMBTU/ hr*	***93.00***	***63.60***		***156.60***
Process Fluid	*- - -*	*Therminol 55*	*Therminol 55*		
Process Mass Flow Rate, Total	*Lb/ hr*	*2,497,300*	*2,497,300*		
Process Bulk Velocity (allow. / calc.)	*ft/ s*	*- - - / 13*	*- - - / 9*		
Process Mass Velocity (min./ calc.)	*Lb/ s ft2*	*- - - / 624*	*- - - / 432*		
Coking Allowance (dP calcs)	*in*				
Pressure Drop, Clean (allow. / calc.)	*psi*	*< -------* ***35*** */*	***34*** *------- >*		
Pressure Drop, Fouled (allow. / calc.)	*psi*	*< ------- /*	*------- >*		
Average Heat Flux (allowable)	*BTU/ hr ft2*	*0*			
Average Heat Flux (calculated)	*BTU/ hr ft2*	***13,068***			
Maximum Heat Flux (allowable)	*BTU/ hr ft2*				
Maximum Heat Flux (calculated)	*BTU/ hr ft2*	*19,600*	*22,430*		
Fouling Factor, Internal	*hr ft2 °F/ BTU*	*0.001*	*0.001*		
Corrosion or Erosion Characteristics	*- - -*				
Max. Film Temperature (allow. / calc.)	*°F*	*550 / 484*	*550 / 415*		
Inlet Conditions:					
Temperature	*°F*	***334***	***289***		
Pressure	*psig*	***108***	***119***		
Mass Flow Rate, Liquid	*Lb/ hr*		*2,497,300*		
Mass Flow Rate, Vapor	*Lb/ hr*		*0*		
Weight Percent, Liquid / Vapor	*wt%*		*100% / 0.0%*		
Density, Liquid / Vapor	*Lb/ ft3*		*49.20 /*		
Molecular Weight, Liquid / Vapor	*Lb/ Lbmole*		*/*		
Viscosity, Liquid / Vapor	*cp*		*1.418 /*		
Specific Heat, Liquid / Vapor	*BTU/ Lb °F*		*0.561 /*		
Thermal Conductivity, Liquid/Vapor	*BTU/hr ft °F*		*0.066 /*		
Surface Tension, Liquid	*dyne/ cm*				
Outlet Conditions:					
Temperature	*°F*	***400***	***334***		
Pressure	*psig*	***85.0***	***108***		
Mass Flow Rate, Liquid	*Lb/ hr*	*2,497,300*			
Mass Flow Rate, Vapor	*Lb/ hr*	*0*			
Weight Percent, Liquid / Vapor	*wt%*	*100% / 0.0%*			
Density, Liquid / Vapor	*Lb/ ft3*	*46.50 /*			
Molecular Weight, Liquid / Vapor	*Lb/ Lbmole*	*/*			
Viscosity, Liquid / Vapor	*cp*	*0.718 /*			
Specific Heat, Liquid / Vapor	*BTU/ Lb °F*	*0.612 /*			
Thermal Conductivity, Liquid/Vapor	*BTU/hr ft °F*	*0.062 /*			
Surface Tension, Liquid	*dyne/ cm*				

Ftnt & Rev

COMBUSTION DESIGN CONDITIONS

Overall Performance:		RADIANT	CONVECTION		TOTAL	Ftnt & Rev
Operating Case	- - -	**Case A: Design -**	**Hot Oil Only**			
Service	- - -	Hot Oil	Hot Oil			
Excess Air	mol%				15.0%	
Calculated Heat Release (LHV)	MMBTU/ hr				173.61	
Guaranteed Efficiency	HR%				**89.2%**	
Calculated Efficiency	HR%				90.2%	
Radiation Loss	HR%				1.5%	
Flow Rate, Combustion Gen./ Imported	Lb/ hr	169,013	/ 0		169,013	
Flue Gas Temperature Leaving Section	°F	**1,582**	**388**			
Flue Gas Mass Velocity	Lb/ sec ft2		0.452			

Fuel(s) Data:		Design	C2		
LHV	BTU/ scf	942	1,618		
LHV	BTU/ Lb	21,003	20,420		
P @ Burner	psig	30	30		
T @ Burner	°F	100	100		
MW	Lb/ Lbmole	17.01	30.07		
μ @ ??? °F	cp	- - -	- - -		
μ @ ??? °F	cp	- - -	- - -		
Atomizing Media		- - -	- - -		
Atom. Media P & T		- - -	- - -		
Components:					
N	wt%	- - -	- - -		
S	wt%	- - -	- - -		
Ash	wt%	- - -	- - -		
Ni	ppm	- - -	- - -		
Va	ppm	- - -	- - -		
Na	ppm	- - -	- - -		
Fe	ppm	- - -	- - -		
H2	mol%	0.00	0.00		
O2	mol%	0.00	0.00		
N2 + Ar	mol%	1.08	0.00		
CO	mol%	0.00	0.00		
CO2	mol%	0.00	0.00		
CH4	mol%	93.04	0.00		
C2H6	mol%	5.77	100.0		
C2H4	mol%	0.00	0.00		
C3H8	mol%	0.11	0.00		
C3H6	mol%	0.00	0.00		
C4H10	mol%	0.00	0.00		
C4H8	mol%	0.00	0.00		
C5H12	mol%	0.00	0.00		
C5H10	mol%	0.00	0.00		
C6+	mol%	0.00	0.00		
Sulphur	ppmv	0.25	0.00		
SO2	mol%	0.00	0.00		
NH3	mol%	0.00	0.00		
H2O	mol%	0.00	0.00		
spare	mol%	0.00	0.00		

Burner Design:			
OEM	- - -	**Callidus, Zeeco or John Zink**	
Type	- - -	BACT - Best Available Combustion Technology	
Quantities	- - -	12	Burners
Model No.1	- - -	TBA	Cylindrical
Model No.2	- - -	None	
Windbox	- - -	yes ...	w/ opposed blade registers
Location	- - -	Floor ... 17.87	ft. diameter burner circle
Pilot Design:			
Type	- - -	Continuous	Self-Inspirating
Model	- - -	TBA	
Ignition	- - -	Electric	requires elec.ign.system
Heat Release	- -	> 90,000 BTU/ hr on ...	Design RFG

Burner Performance:				Ftnt & Rev
Minimum Heat Release	MMBTU/ hr	3.18		
Design Heat Release	MMBTU/ hr	14.47		
Maximum Heat Release	MMBTU/ hr	15.91		
Burner Turndown	Max:Min	5.00		
Volumetric Ht. Release	BTU/ hr ft3	4,550		
Draft @ Arch	inH2O	0.40		
Draft @ Burner	inH2O	1.00		
Combustion Air T @ Burner	°F	60		
Flue Gas T @ Burner	°F	1,390		
Guaranteed Emissions:		**<-- Combined -->**		
Basis of Guarantee	- - -	LHV Basis,3% O2 Dry		
NOx Emissions	lb/MMBtu	0.010		[C]
SOx Emissions	- - -	no quote		
CO Emissions	lb/MMBtu	0.030		
UHC Emissions	lb/MMBtu	0.030		
VOC Emissions	lb/MMBtu	0.030		
SPM10 Emissions	lb/MMBtu	0.008		
Noise Emissions	dBA @ 3ft	85.0		[D]

Special Burner Features &/ or Services:

Reed Wall	None
Pilot Detection	Ionization Rod
Main Detection	UV Scanner
Burner Test	Yes; per Attachment A
CFD/ CF Models	None / None

Clearances:		Vertical				Horizontal	
... for Gas Firing:		**Minimum**	**Calculated**			**Minimum**	**Calculated**
... from burner CL ...		per Std 560	per THI Design			per Std 560	per THI Design
to Tube CL	ft	**36.26**	**61.40**	to Tube CL	ft	**5.48**	**5.71**
to Refractory	ft	36.26	58.40	to Refractory	ft	n / a	n / a

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COMBUSTION DESIGN CONDITIONS

Overall Performance:		RADIANT	CONVECTION		TOTAL	Ftnt & Rev
Operating Case	- - -	**Case B: Design Hot Oil + Regen**				
Service	- - -	Hot Oil	Hot Oil			
Excess Air	mol%				15.0%	
Calculated Heat Release (LHV)	MMBTU/ hr				170.22	
Guaranteed Efficiency	HR%				**89.2%**	
Calculated Efficiency	HR%				92.0%	
Radiation Loss	HR%				1.5%	
Flow Rate, Combustion Gen./ Imported	Lb/ hr	165,710	/ 44,770		210,480	
Flue Gas Temperature Leaving Section	°F	**1,559**	**399**			
Flue Gas Mass Velocity	Lb/ sec ft2		0.563			

Fuel(s) Data:		Design	C2		
LHV	BTU/ scf	942	1,618		
LHV	BTU/ Lb	21,003	20,420		
P @ Brnr	psig	30	30		
T @ Brnr	°F	100	100		
MW	Lb/ Lbmole	17.01	30.07		
μ @ ??? °F	cp	- - -	- - -		
μ @ ??? °F	cp	- - -	- - -		
Atomizing Media		- - -	- - -		
Atom. Media P & T		- - -	- - -		
Components:					
N	wt%	- - -	- - -		
S	wt%	- - -	- - -		
Ash	wt%	- - -	- - -		
Ni	ppm	- - -	- - -		
Va	ppm	- - -	- - -		
Na	ppm	- - -	- - -		
Fe	ppm	- - -	- - -		
H2	mol%	0.00	0.00		
O2	mol%	0.00	0.00		
N2 + Ar	mol%	1.08	0.00		
CO	mol%	0.00	0.00		
CO2	mol%	0.00	0.00		
CH4	mol%	93.04	0.00		
C2H6	mol%	5.77	100.0		
C2H4	mol%	0.00	0.00		
C3H8	mol%	0.11	0.00		
C3H6	mol%	0.00	0.00		
C4H10	mol%	0.00	0.00		
C4H8	mol%	0.00	0.00		
C5H12	mol%	0.00	0.00		
C5H10	mol%	0.00	0.00		
C6+	mol%	0.00	0.00		
Sulphur	mol%	0.25	0.00		
SO2	mol%	0.00	0.00		
NH3	mol%	0.00	0.00		
H2O	mol%	0.00	0.00		
spare	mol%	0.00	0.00		

Burner Design:			
OEM	- - -	**Callidus, Zeeco or John Zink**	
Type	- - -	BACT - Best Available Combustion Technology	
Quantities	- - -	12	Burners
Model No.1	- - -	TBA	Cylindrical
Model No.2	- - -	None	
Windbox	- - -	yes ...	w/ opposed blade registers
Location	- - -	Floor ... 17.87	ft. diameter burner circle
Pilot Design:			
Type	- - -	Continuous	Self-Inspirating
Model	- - -	TBA	
Ignition	- - -	Electric	requires elec.ign.system
Heat Release	- -	> 90,000 BTU/ hr on ...	Design RFG

Burner Performance:				Ftnt & Rev
Minimum Heat Release	MMBTU/ hr	3.18		
Calculated Heat Release	MMBTU/ hr	14.18		
Maximum Heat Release	MMBTU/ hr	15.91		
Burner Turndown	Max:Min	5.00		
Volumetric Ht. Release	BTU/ hr ft3	4,550		
Draft @ Arch	inH2O	0.40		
Draft @ Burner	inH2O	1.00		
Combustion Air T @ Burner	°F	60		
Flue Gas T @ Burner	°F	1,359		
Guaranteed Emissions:		**<-- Combined -->**		
Basis of Guarantee	- - -	LHV Basis,3% O2 Dry		
NOx Emissions	lb/MMBtu	0.010		[C]
SOx Emissions	- - -	no quote		
CO Emissions	lb/MMBtu	0.030		
UHC Emissions	lb/MMBtu	0.030		
VOC Emissions	lb/MMBtu	0.030		
SPM10 Emissions	lb/MMBtu	0.008		
Noise Emissions	dBA @ 3ft	85.0		[D]

Special Burner Features &/ or Services:	
Reed Wall	None
Pilot Detection	Ionization Rod
Main Detection	UV Scanner
Burner Test	Yes; per Attachment A
CFD/ CF Models	None / None

Clearances:		Vertical				Horizontal	
... Basis: Gas Firing		**Minimum**	**Actual**			**Minimum**	**Actual**
... from burner CL ...		per Std 560	per THI Design			per Std 560	per THI Design
to Tube CL	ft	**36.26**	**61.40**	to Tube CL	ft	**5.48**	**5.71**
to Refractory	ft	36.26	58.40	to Refractory	ft	n / a	n / a

PRESSURE PARTS DESIGN

						Ftnt & Rev
Coil Design:		**RADIANT**	**RADIANT**	**SHIELD**	**CONVECTION**	
Service	- - -	Hot Oil	Hot Oil	Hot Oil	Hot Oil	
Design Basis for Tube Temperature	- - -	API Standard 530	API Standard 530	API Standard 530	API Standard 530	
Design Basis for Tube Wall Thickness	- - -	API Standard 530	API Standard 530	API Standard 530	API Standard 530	
Design Life	hr	100,000	100,000	100,000	100,000	
Design Pressure (elastic / rupture)	psig	**200 / 200**	**200 / 200**	**200 / 200**	**200 / 200**	
Design Fluid Temperature	°F	400	400	331	331	
Design Temperature Allowance	°F	25	25	25	25	
Design Corrosion Allowance (tubes/fittin	in	0.125 / 0.125	0.125 / 0.125	0.125 / 0.125	0.125 / 0.125	
Maximum Tube Temperature (clean)	°F	485	512			
Maximum Tube Temperature (fouled)	°F	508	538	451	451	
Design Tube Temperature	°F	**533**	**563**	**522**	**522**	
Inside Film Coefficient	BTU/ hr ft2 °F	335	211	177	177	
Weld Inspection	RT or Other	100 of 100%	100 of 100%	100 of 100%	100 of 100%	
Weld Heat Treatment	s.rel., t.stab. or none	None	None	None	None	
Hydrostatic Test Pressure	psig	per API	per API	per API	per API	
Coil Arrangement:		**Vertical**	**Vertical**	**Horizontal**	**Horizontal**	
Coil Type	- - -	Serpentine	Serpentine	Serpentine	Serpentine	
Tube Material (pipe or tube spec)	ASTM	A106 GrB	A106 GrB	A106 GrB	A106 GrB	
Supplementary Mfg Requirements	ASTM	None	None	None	None	
Tube Outside Diameter	in	5.563	6.625	6.625	6.625	
Tube Wall Thickness (aw ~~/ mw~~)	in	0.258	0.280	0.280	0.280	
Number of Cells (radiant or convection)	- - -	1	1	1	1	
Number of Flow Passes	- - -	8	8	8	8	
Number of Tubes per Row	- - -			8	8	
Overall Tube Length	ft	55.09	55.25	30.75	30.75	
Effective Tube Length / Tube Circle Dia.	ft	56.75 / 29.28	56.75 / 29.28	29.00	29.00	
Number of Bare Tubes	- - -	**48**	**32**	**24**		
Total Exposed Surface	ft2	3,967	3,150	1,207		
Number of Ext.Surf. Tubes	- - -				**72**	
Total Exposed Surface	ft2				39,502	
Tube Spacing (horizontal / tube centers)	in	- - - / 15.00	/ 12.00	12.00 / 12.00	12.00 / 12.00	
Tube Spacing (horizontal to refractory)	in	7.50	9.00	6.00	6.00	
Coil Fittings:		**Hot Oil**	**Hot Oil**	**Hot Oil**	**Hot Oil**	
Fitting Type	- - -	LR 180° U-Bends	SR 180° U-Bends	SR 180° U-Bends	SR 180° U-Bends	
Fitting Material	ASTM	A234 WPB	A234 WPB	A234 WPB	A234 WPB	
Supplementary Mfg Requirements	ASTM	None	None	None	None	
Fitting Outside Diameter	in	5.563	6.625	6.625	6.625	
Fitting Wall Thickness (aw ~~/ mw~~)	in	0.258	0.280	0.280	0.280	
Fitting Location	internal or external	Internal	Internal	External	External	
Tube Attachment	welded or rolled	Welded	Welded	Welded	Welded	
Coil Terminals:		**Outlet**			**Inlet**	
Terminal Type	beveled or flanged	Flanged			Flanged	
Flange Material	ASTM	A105			A105	
Supplementary Mfg Requirements	ASTM	None			None	
Flange Size and Rating	NPS/ ASME	5" NPS / 300 #			6" NPS / 300 #	
Flange Type	RFWN or RTJ	RFWN			RFWN	
Location	- - -	Radiant Roof			Terminal End	
Extended Surface:				**CONVECTION**	**CONVECTION**	
Service	- - -			Hot Oil	Hot Oil	
Fin or Stud Row Number	starting @ bottom			Rows 1 - 2	Rows 3 - 9	
Ext. Surface Type	seg.fins, solid fins, studs			Solid Fins	Solid Fins	
Fin/Stud Material	- - -			C.S.	C.S.	
Fin/Stud Dimensions	H x T, in			0.5 x 0.06"	1 x 0.06"	
Fin/Stud Density	fin/ in or stud/ plane			4 fins/in	5 fins/in	
Maximum Fin/Stud Temperature	°F			599	675	

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PRESSURE PARTS DESIGN (continued)

		RADIANT	SHIELD	CONVECTION	
Crossovers:					
Type, location / connections	- - -	External	/ Flanged	None	
Tube / Fittings Material	ASTM	A106 GrB	/ A234 WPB		
Tube & Fitting Outside Diameter	in	< -------	6.625 ------- >		
Tube & Fitting Wall Thickness (aw / mw)	in	< ------- 0.280	/ 0.245 ------- >		

Manifold(s) Design Basis:		ASME B31.3 - 2006 Edition			
Design Life	hr	100000	Design Pressure	psig	200
Corrosion Allowance	in	0.125			

Location	- - -	Inlet 1	Inlet 2	Outlet 1	Outlet 2
Type	- - -	Segmented, Log	Tee, horizontal	Ring	Tee, horizontal
Quantity	- - -	Two (2)	One (1)	Two (2)	One (1)
Pipe Material	ASTM	A106 GrB	A106 GrB	A106 GrB	A106 GrB
Tube Connection Type	extrusion, olet, etc.	Weld o let		Weld o let	
Manifold Terminals	beveled or flanged		20" 300# WNRF		18" 300# WNRF
Process Design:					
Number of Flow Passes (Connections)	- - -	4	8	4	8
Design Temperature Allowance / Temp	°F	25 / 314	25 / 314	25 / 425	25 / 425
Connection Inside Diameter	in	6.065	6.065	5.047	5.047
100% Flow Area, All Passes	in2	116	231	80	160
Manifold Outside Diameter(s)	in	16.0	20.0	12.8	18.0
Manifold Wall Thickness; aw	in	0.375	0.375	0.375	0.375
Manifold Relative Size, % Coil FA	%	158%	126%	141%	146%
Mechanical Design:					
Allowable Stress @ Dsn T (Table A-1)	psi				
Quality Factor	- - -				
Temperature Coef. (Table 304.1.1)	- - -				
Wall Thickness, Minimum	in				
Manifold Wall Thickness, % of Calc. Minimum					

COIL & MANIFOLD SUPPORTS DESIGN

		RADIANT	SHIELD	CONVECTION	
Tube Supports:					
Service	- - -	Hot Oil	Hot Oil	Hot Oil	
Location	Top, Bottom, Ends	Top	Ends	Ends	
Support Type	casting, tubesht, spring, etc.	casting	tubesheet	tubesheet	
Material	ASTM	A351 HK40	A283 Gr. C	A283 Gr. C	
Support Thickness	in		0.50	0.50	
Refractory Type and Thickness	- - -		ref. refractory	ref. refractory	
Anchor Material and Type	- - -		section below	section below	
Intermediate Guides & Supports:		Yes; One	Yes; One	Yes; One	
Location	- - -	mid- Radiant	Intermediate	Intermediate	
Guide/ Support Type	casting, spring, etc.	casting	Casting	Casting	
Material	ASTM	A351 HK40	A351 HK40	A351 HK40	
Spacing, average	ft	28.38	14.50	14.50	
Tube Guides:	Top, Bottom, Ends	Bottom	None	None	
Material	ASTM	A312 T310			
Manifold Supports:		Outlet Manifold		Intlet Manifold	
Material	ASTM	Carbon Steel		Carbon Steel	
Materials Design & Supply	- - -	THI		THI	
Location	Top, Bottom, Ends	As Required		As Required	
Support Type	roller, shoe, spring, etc.	TBA		TBA	
Number of Supports	- - -	TBA		TBA	

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CASING / REFRACTORY SYSTEMS DESIGN

Radiant Section Design:		**PLENUM**	**FLOOR**	**SHIELDED**	**ARCH**
Total Refractory Thickness	in		**12.5**	**4.0**	**6.0**
Hot Face Temperature (design)	°F		2,500°	2,300°	2,300°
Hot Face Temperaure (calculated)	°F		1,382	1,264	1,582
Hot Face Layer	in/ - - -		2.5/ HD Firebrick	1/ 8# CF Blanket	1/ 8# CF Blanket
Back-Up Layer No.1	in/ - - -		10/ LW Castable	1/ 8# CF Blanket	1/ 8# CF Blanket
Back-Up Layer No.2	in/ - - -		None	2/ 8# CF Blanket	4/ 8# CF Blanket
Foil Vapor Barrier	in/ - - -		None	None	None
Castable Reinforcement (SS Needles)	wt%		None	None	None
Anchors / Tie Backs:	- - -		**None**	**Pins & Clips**	**Pins & Clips**
Material	- - -			304 S.S.	310 S.S.
Attachment	- - -			Welded	Welded
Casing:					
Material	in/ ASTM		**0.250 / A36**	**0.250 / A36**	**0.250 / A36**
Internal Coating	- - -		None	Required	Required
External Temp, guaranteed / calculated	°F		150 / 147	150 / 145	150 / 148
Comments / Clarifications	- - -	None	9' 0" min.elev.	w/o cfb wraps	w/ cfb wraps
			Field Installed		

		SIDEWALLS		**ENDWALLS**	
Convection Section Design:		**SHIELD**	**FINNED**	**TUBESHEETS**	**HEADER BOXES**
Total Refractory Thickness	in	**5.0**	**5.0**	**4.0**	**2.0**
Hot Face Temperature (design)	°F	2,000°	2,000°	2,000°	2,300°
Hot Face Temperaure (calculated)	°F	985	985	985	430
Hot Face Layer	in/ - - -	5/ SLW Castable	5/ SLW Castable	4/ SLW Castable	2/ 8# CF Blanket
Back-Up Layer No.1	in/ - - -	None	None	None	None
Back-Up Layer No.2	in/ - - -	None	None		
Foil Vapor Barrier	in/ - - -	None	None	None	None
Castable Reinforcement (SS Needles)	wt%	None	None	None	None
Anchors / Tie Backs:	- - -	**V's**	**V's**	**V's**	**Pins & Clips**
Material	- - -	310 S.S.	304 S.S.	310/304 S.S.	304 S.S.
Attachment	- - -	Welded	Welded	Welded	Welded
Casing:					
Material	in/ ASTM	**0.1875 / A36**	**0.1875 / A36**		**0.1875 / A36**
Internal Coating	- - -	Required	Required		Required
External Temp, guaranteed / calculated	°F	150 / 147	150 / 147		150 / 106
Comments / Clarifications	- - -	w/o cfb wraps	w/o cfb wraps	304SS Ferrules	w/o cfb wraps
	- - -	Water washing / cleaning lanes: none		of 0' - 0" height.	std. bolted assembly

		FLUE GAS DUCTS		**STUB STACK**	
Stack & Uptakes Design:		**BREECHING**	**UPTAKES**	**BELOW DAMPER**	
Quantity		**One**	**Two**	< - - - - - **One** - - - - - >	
Type / Location	- - -	Full L / Conv	Flo.Bal. / Conv	Self Supporting	/ on Heater
Length / Metal Outside Diameter (top)	ft/ ft	n/ a / n/ a	4.9 / 9.4	**20**	/ **7.00**
Discharge Elev., minimum/ calculated	ft/ ft	n/ a / n/ a	n/ a / n/ a	0	/ **131**
Total Refractory Thickness	in	**2.0**	**2.0**	**2.0**	
Hot Face Temperature (design)	°F	2,200°	2,200°	2,200°	
Hot Face Temperaure (calculated)	°F	388	388	388	
Hot Face Layer	in/ - - -	2/ LW Castable	2/ LW Castable	2/ LW Castable	
Back-Up Layer No.1	in/ - - -	None	None	None	
Castable Reinforcement (SS Needles)		None	None	None	
Anchors / Tie Backs:	- - -	**Fence Pickets**	**Fence Pickets**	**Fence Pickets**	
Material	- - -	C.S.	C.S.	C.S.	
Attachment	- - -	Welded	Welded	Welded	
Casing:					
Minimum Thickness/ Material	in/ ASTM	**0.1875 / A36**	**0.1875 / A36**	**0.250 / A36**	
Corrosion Allowance	in	None	None	0.0625	
Internal Coating	- - -	None	None	None	
External Temp, guaranteed / calculated	°F	150 / 142	150 / 142	150 / 142	
Comments / Clarifications	- - -				

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MECHANICAL / STRUCTURAL DESIGN BASIS

Refractory & Coatings Design:

Refractory Design	**150°F Casing Temperature** w/ Ambient Conditions of 3 MPH & 90°F	
Refractory Dryout	SHOP dryout = None // FIELD dryout (per ES -1-9) within 3 months of shipment is recommended.	
Coating, Internal	12 dftmil CTE (Coal Tar Epoxy) on SP-6 Surface	
Coating, External	Technip Spec.: DH721033-000-JSS-2310-001-A, System CS-1	[E]

Applicable Standards:

API	Std 560; Fired Heaters for General Refinery	AISC	Specification for Design, ... Steel for Buildings
API	Std 530; Calc. of Heater Tube Thickness ...	AWS	D 1.1; Structural Welding Code
ASME	B31.3, Chemical Plant and ... Piping	ASTM	tube/ smls pipe/ fitting spec's noted herein
ASME	Sections I, II, VIII; B&PV Code	ASTM	refractories per C27, C155, C401 & C612
ASME	Section V; Non Destructive Examination	NFPA	NFPA 70; National Electrical Code

Wind Design:		**Seismic Design:**	
Spec. or Standard	ASCE 7-10	Spec. or Standard	ASCE 7-10
Velocity/ Imp. Factor	150 mph / 1	Site Class/ Imp. Factor	D / 1.25
Site Exposure	"C"	spare	
Physical Design:		**Site Design Basis:**	
Plot Limitations	None	Site Elevation	69 ft AMSL
Tube Limitations	None	Stack Design T	105 °F
Firebox Pressure	Negative, per Std 560	FG Discharge El.	
		Area Classification	Class 1, Division 2, Groups C & D

MAJOR SUBSYSTEMS & ACCESSORIES

Major Subsystems:		**Major Accessories:**		
Burner Management	Included in base pricing	Casing/ Tube Seals	32	TubeSox; Radiant & Conv.
Burner Piping	Included Burner - Heater Edge	Observation Doors	24	5"x 9" w/o glass
Forced/ Ind. Draft	Induced Draft Fan Included	Observation Doors	None	
Air Preheat System	None in job scope	Observation Doors	None	
NOx Reduction Sys.	Integral SCR included	Access Doors	3	Std 24" x 24"
FBox Purge Fan	None in job scope	Access Doors	None	
FBox Purge Eductor	None in job scope	Tube Pulling Doors	2	Std 24" x 24"
ACWarning Lights	None	Pressure Relief Doors	None	
Painter's Trolley	None	spare	None	

Casing Penetrations			**Pressure Part Penetrations**		
Firebox Purge/ Snuff	8	2"NPS 150# RFWN	Coil TSTC's, Radiant	1	TSTC's / pass
FG Ammonia Slip	4	4"NPS 150# RFWN	Coil TSTC's, Convection	0	
FG Temperature	16	1.5"NPS 150# RFWN	Process TI conn's	2	1.5"NPS 300# RFWN's/ pass
FG Pressure	16	2"NPS 3000# Coupling	Process PI conn's	None	
FG Comp. (O2)	3	4"NPS 150# RFWN	Velocity Steam conn's	None	
FG Comp. (EPA)	4	4"NPS 150# RFWN	S/A Decoking conn's	None	
FG Comp. (CEMS)	1	4"NPS 150# RFWN	Vent / Drain conn's	None	

Dampers:	**spare**	**Uptake Ducts** quantity = 2	**Stack** quantity = 0
Function		Control / Flue Gas Flow Balancing	
Design		Multiple, Opposed Acting	
Materials		Carbon Steel Blades & Shafts	
Bearings		Conventional Pipe Sleeve "Bearings"	
Operator		Manual; cable to platform	
Positioner			
Instruments			

Sootblowers:	Qty	Type	Location	FG T	Material	Steam T & P	O.E.M. / Ref.
Lane 1:							
Lane 2 :							

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MAJOR SUBSYSTEMS & ACCESSORIES (continued)

Proposed Ladders & Platforms

Proposal & Design Basis:

1) Construction: 100% Galvanized A36 CS per API Standard 560 / ISO 13705
2) Provisions for External Coating(s) / Painting: None, except as explicitly set forth in THI's proposal
3) Additional L&P's: can be provided per the basis set forth in Sections 8 & 9 of THI's proposal

Component	Qty	Width	Length	Arc	O.D.	Weight	Price
	(- -)	(ft)	(ft)	(°)	(ft)	(Lb)	(US$)
Stair Tower 72 ft tall	1	10.00	0.00			54,335	
Radiant Platforms							
Hearth Platform	1	3.00	38.24	360	38.24	9,300	
Intermediate Platforms	1	3.00	38.24	360	38.24	9,300	
Ladder to Grade	1	3.00	0.00	0	0.00	430	
Stair to Grade	0	3.00	0.00	0	0.00	0	
Convection Platforms							
Conv. End Platforms	4	4.00	10.36			5,310	
Conv. Side Platforms	3	3.00	40.25			10,870	
Ladder to Hearth	1	3.00	65.95			1,750	
Intermediate Platforms	1	3.00	4.00			420	
Uptake Platforms	2	3.00	3.00			630	
Ladder to Upper Conv.	2	3.00	6.00			900	
Operation Platforms							
Flow Balance Station Platfc	2	3.00		0	0.00	2,100	
Ladder to Upper Conv.	2	3.00		0	0.00	750	
ID Fan Platform	1	5.00		360	18.00	6,740	
Ladder to Conv.	1	3.00	20.76			620	
Intermediate Platforms	0	3.00	4.00			0	
EPA Platform	1	3.00		270	14.00	2,570	
Ladder to Dmpr	1	3.00	25.00			730	
Intermediate Pltfm	0	3.00		90	14.00	0	
Totals for Proposed Platforms						**52,420**	
Total for Proposed Stairtower						**54,335**	

CLARIFICATIONS, FOOTNOTES & REVISIONS

Refractory Systems Abbreviations Key:

HD Firebrick = High Density Firebrick;
CF Blanket = Ceramic Fiber Blanket - Thermal Ceramics Kaowool or equivalent;
HTCF Blanket - High Temperature Ceramic Fiber Blanket - Thermal Ceramics Cerachem or equivalent.
CF Modules - Ceramic Fiber Modules - Thermal Ceramics Pyro-Fold M or equivalent.
V Block - Insulating Vermiculite Block - Thermal Ceramics TR-19 or equivalent.
1:2:4 LHV = Shop mix castable of 1:2:4 specification, 1:0:6 LHV = Shop mix castable of 1:0:6 spec.
CF Board = Ceramic Fiber Board - Thermal Ceramics Kaowool M Board or equivalent
LW Castable = Light Weight Castable - Thermal Ceramics Kaolite 2200 or equivalent
LWLI Castable = Light Weight Low Iron Castable - Thermal Ceramics Kaolite 2300LI or equivalent
SLW Castable = Super Light Weight Castable - Thermal Ceramics Kaolite 2000LI or equivalent

[A] Indicated guaranteed process pressure drop excludes process dP of Inlet and Outlet manifolds [A]
[B] During turndown operations, this heater may experience CO "breakthrough". This undesirable phenomena is a byproduc of low NOx burner design / low firebox temperatures that are unable to force the CO oxidation reaction to completion. [B]
[C] From design to maximum heat release. [C]
[D] Sound Pressure Level. [D]
[E] Surface Preparation - Sandblast SSPC-SP-6 [E]
Primer: Inorganic Zinc, 2 - 3 mils DFT
Intermediate: Amine Epoxy, 2 - 3 mils DFT
Finish: Polyurethane, 2 - 3 mils DFT, Color: Gray FS 16440

Owner Ref.: **300-HR-001** THI Ref.: **P13-8431A**

Item	Units	Case B: Design	"Test Block"	Case A: Design		Ftnt & Rev
Overview:		***INDUCED DRAFT (ID) FAN ASSEMBLY***				
Fan Design Basis	mass.flow.%	***115% of Heater Design Mass Flows***				
Quantity of Assemblies	- - / %	*One (1) Induced Draft Fan Assembly*				
Location(s)	- - -	*Above Convection*				
Area Classification	NEC	*Class 1, Division 2, Groups C & D*				
Process Design:		***Case B: Design***	***"Test Block"***	***Case A: Design***		
Operating Case:		***Hot Oil + Regen***		***Hot Oil Only***		
Mass Flow Rate/ % Htr Design	Lb/ hr	*210,702 / 100%*	*242,308 / 115%*	*169,013 / 100%*		
Volumetric Flow/ % Htr Design	aft3/ min	*79,477 / 100%*	*102,038 / 128%*	*62,917 / 100%*		
Density, @ Suction & noted T & P	Lb/ ft3	*0.0442*	*0.0396*	*0.0448*		
Design Allowances, Temp./ SP	°F/ %	*- - - / - - -*	*100 °F / 165%*	*- - - / - - -*		
Temperature @ Suction, Design	°F	*399*	*499*	*388*		
Static Pressure @ Suction, Design	inH2O	*-3.5*	*-5.7*	*-2.4*		
Site Elevation/ Atm. Pressure	ftAMSL/ psia	*69 / 14.7*	*69 / 14.7*	*69 / 14.7*		
Static Pressure Rise (min./ guar.)	inH2O	*4.3 / t.b.g.*	***7.1*** */ t.b.g.*	*3.1 / t.b.g.*		
Static Efficiency (min./ guar.)	%	*- - - / t.b.g.*	*- - - / t.b.g.*	*- - - / t.b.g.*		
Fan Speed (allowable/ actual)	RPM	*1,200 / t.b.g.*	*1,200 / t.b.g.*	*1,200 / t.b.g.*		
Sound Pressure (allowable/ guar.)	dBA	*< 85 / t.b.g.*	*< 85 / t.b.g.*	*< 85 / t.b.g.*		
Fan Mechanical Design:	fan OEM	***t.b.d.***				
OEM Reference	- - -					
OEM Model &/or Type-Size	- - -					
Arrangement	- - -	*Arrangement 7*				
Brake Power (calculated)	HP	*<200 if possible*				
Temperature, Maximum Operating	°F	*599*				
Casing Description	- - -	*Split Casing, w/ Flanged Connections*				
Casing Material(s)	- - -	*A36 CS of at least 0.25" thickness*				
Blade Description	- - -	*TBQ*				
Blade & Rotor Assembly Material(s)	- - -	*TBQ*				
Shaft Description	- - -	*TBQ*				
Shaft Seals Description	- - -	*TBQ*				
Bearings Description	- - -	*TBQ*				
Bearing Instrumentation Description	- - -	*Metrix ST5491E Vibration Transmitter or equivalent*				
Coupling Description	- - -	*TBQ*				
Silencer Description	- - -	*None*				
External Insulation Provisions	- - -	*Yes; pins by fan OEM for field insulation*				
External Coatings & Surface Prep.	- - -	*From design to maximum heat release.*				
	- - -	*Sound Pressure Level.*				
	- - -					
Fan Control Design:	dmpr OEM	***t.b.d.***				
VFD Description	- - -	*Variable Torque, 460V / 60Hz / 3ph*				
VFD Rating	- - -	*Max Speed - 1200 RPM*				
Damper Description	- - -	*None*				
Actuator Description	- - -	*None*				
Actuator Operation	- - -	*None*				
External Coatings & Prep.	- - -	*< ---- O.E.M.'s Standard Two Coat System on SP-6 (or equal) surface ---- >*				
Motor Design:	mtr OEM	***t.b.d.***				
OEM Reference	- - -					
Motor Type / Frame Size	- - -					
Rated Power w/ SF @ Speed	NEMA					
Local Power	V/ Hz/ ph					
Rotor Description	- - -					
Shaft Seals Description	- - -					
Bearings Description	- - -					
Insulation Description	- - -					
External Coatings & Surface Prep.	- - -	*< ---- O.E.M.'s Standard Two Coat System on SP-6 (or equal) surface ---- >*				
Purchase Specifications:	- - -	*PIP ELSMT01 AC Squirrel Cage Induction Motor Spec -600 Volts and Below*				
	- - -	*PIP ELSPS01 Elect Requirement for Packaged Equipment*				
	- - -	*API 560 4th edition*				

AMERICAN ENGINEERING SYSTEM of UNITS ***TULSA HEATERS INC.***	***ID FAN DATA SHEET*** ***P13-8431A- HTRds - Rev.00*** ***Page 10 of 13***

Owner:	**Lone Star NGL**	Owner Ref.:	**300-HR-001**	Ftnt
Purchaser	S&B Engineers and Constructors, Ltd.	Purch. Ref.:	C-1498	&
Heater OEM:	***TULSA HEATERS INC.***	***THI*** *Ref.:*	***P13-8431A***	Rev
DeNOx OEM:	***t.b.d.***	DeNOx OEM Ref.:	***t.b.d.***	
Location:	*Mont Belvieu*	Unit No:	*Train 3*	
System:	***Induced Draft upflow SCR w/ Integral Vector Correction, w/ AFCU and AIG***			

PROCESS DESIGN CONDITIONS

DeNOx System Design Basis		***Design***			
DeNOx Operating Basis		*Case A: Design*	*Case B: Design*		
		Hot Oil Only	*Hot Oil + Regen*		
DeNOx Combustion Case		*Natural Gas @ 15% XSAir*			
Reactor Performance:					
NOx Reduction Efficiency (calc/ guar)	*vol%*	***76%*** / *t.b.q.*	***76%*** / *t.b.q.*		
SO2 Oxidation Rate (by THI/ OEM)	*mass%*				
Ammonia Slip (calc./ guar.)	*ppmvd*	/ < 5.0	/ < 5.0		
Turndown Capability (calc./ guar.)	- - -				
Ammonia Consumption (calc./ guar.)	*Lb/ hr*	*12.0* / - - -	*14.9* / - - -		
Reactor dP - clean (allow./ guar.)	*inH2O*	*1.5* / *t.b.q.*	*1.5* / *t.b.q.*		
Reactant (AIG Charge) Design:	*type*	***Aqueous Ammon***	***Aqueous Ammonia***		
NH3 Concentration	*wt%*	***19%***	***19%***		
Temperature, Flue Gas @ AIG	*°F*	*697*	*701*		
Flow Rate, Diluant + NH3 to AIG	*Lb/ hr*	*192*	*235*		
Flow Rate, Dilution Air	*Lb/ hr*	*180*	*220*		
Molar Ratio, NH3/ NOx	*mole:mole*	*0.932 : 1.00*	*0.931 : 1.00*		
Reactor Charge:	- - -	< ------- ------- -------	***Exclusive of AIG Charge***		------- ------- ------- >
Temperature, Flue Gas	*°F*	*697*	*701*		
Flow Rate, Flue Gas - wet basis	*Lb/ hr*	***169,100***	***210,702***		
Flow Rate, Flue Gas - dry basis	*Lb/ hr*	*150,190*	*187,241*		
Component Flow Rates, Net To Reactor					
O2	*Lb/ hr*	*4,841*	*6,038*		
N2 + Ar	*Lb/ hr*	*122,932*	*153,238*		
CO2	*Lb/ hr*	*22,393*	*27,934*		
H2O	*Lb/ hr*	*18,823*	*23,462*		
NOx	*Lb/hr / ppmvd*	*6.6 29*	*8.2 29*		
SOx	*Lb/hr / ppmvd*	*0.0 / 0*	*0.0 / 0*		
CO	*Lb/hr / ppmvd*	*5.2 / 38*	*6.5 / 38*		
UHC	*Lb/hr / ppmvd*	*5.2 / 66*	*6.5 / 66*		
VOC	*Lb/hr / ppmvd*	*5.2 / 24*	*6.5 / 24*		
SPM	*Lb/ft3 / ppmvd*	*1.4 / 4*	*2.5 / 5*		
Ash	*Lb/hr / ppmwd*	*0.0 / 0*	*0.0 / 0*		
Ni	*Lb/hr / ppmwd*	*0.0 / 0*	*0.0 / 0*		
Va	*Lb/hr / ppmwd*	*0.0 / 0*	*0.0 / 0*		
Na	*Lb/hr / ppmwd*	*0.0 / 0*	*0.0 / 0*		
Fe	*Lb/hr / ppmwd*	*0.0 / 0*	*0.0 / 0*		
Reactor Effluent:	- - -	< ------- ---	***Guaranteed "Not to Exceed" Concentrations***		--- ------- >
NOx	*Lb/hr / ppmvd*	*1.58* / ***7***	*1.97* / ***7***		
SOx	*Lb/hr / ppmvd*	*no quote* /	*no quote* /		
CO	*Lb/hr / ppmvd*	*5.21* / *38*	*6.49* / *38*		
VOC	*Lb/hr / ppmvd*	*14.32* / *66*	*17.83* / *66*		
NH3	*Lb/hr / ppmvd*	*0.42* / ***5***	*0.52* / ***5***		

SCR REACTOR DESIGN

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Reactor Location	OEM's Proprietary Design - integrated between fin rows 4 & 5		
Flow Orientation	Vertical, Up	Design Standard(s)	API RP 536, current edition
Reactor Housing:		**Provisions for ...**	
Size, external casing	29.75 x 9.2 x TBQ (LxWxH)	Future Catalyst	yes; for taller layer
Casing Material	Carbon Steel	Catalyst Loading	yes; one monorail
External Coating	Technip Spec.: DH721033-000-JSS-2310-001-A, System CS-1		
Internal Coating	None		
Refractory Material:		**Instrument Connections:**	
SideWalls	t.b.d.	Flue Gas Pressure	t.b.d.
Roof	t.b.d.	Flue Gas Temperature	t.b.d.
Floor	t.b.d.	Flue Gas Composition	t.b.d.
Design T °F	t.b.d.	Removable Panels	t.b.d.
Design Wt Lb	t.b.d. (excl. refrac.)	Access Doors	t.b.d.

Catalyst:		**Catalyst Constraints:**		
Catalyst OEM:		Combustion Cases	Natural Gas @ 15% XSAir	
Cat. OEM Ref.:	t.b.d. / t.b.d.	Temperatures, design	697 °F	
Type	t.b.d. (plate, honeycomb, etc)	Operating Range	465 < T.Op. < 780	°F (min - max.)
Composition	t.b.d.	Temperature Limits	465 < T.Op. < 780	°F (min - max.)
Module Size ft	t.b.d. (LxWxH)	Foulants & Poisons		
Module Mass Lb	t.b.d. (wt./ module)	SOx ppmvd	0	0
Modules/ Layer	t.b.d.	SPM ppmvd	4	0
Layers, design/ total	t.b.d. / t.b.d.)ne + One (spare)	Ash ppmvd	0	0
No. of Modules	t.b.d. (design basis)	Ni ppmvd	0	0
Cat. Volume ft3	t.b.d. (design basis)	Va ppmvd	0	0
Cat.Life, calculated	t.b.d.	Na ppmvd	0	0
Cat.Life, guaranteed	> 3.0 years (minimum)	Method of Disposal	t.b.d.	t.b.d.
Cat. Velocity, space		Environmental Impact	t.b.d.	t.b.d.
Cat. Velocity, area		spare		

AMMONIA INJECTION SYSTEM

Major Components:			
Ammonia Tank	O.E.M.'s Standard	AFCU - AIG Piping	Piping, Insulation & Tracing by Others
AFCU	O.E.M.'s Standard	AIG	OEM's Proprietary & Proven Design
Local Control Panel	O.E.M.'s Standard	spare	
Ammonia Flow Control Unit (AFCU):		**Ammonia Injection Grid (AIG):**	
Location	Adjacent to heater @ grade	Location	Reactor Inlet - Convection Section
Area Classification	Class 1, Division II, Groups B & C		OEM's Proprietary & Proven Design
Design Code(s)	ASME B31.1	Operating T & P	550 - 656 °F & P < 2.0 psig
Design T&P	750 °F & P < 7.0 psig	Design T & P	O.E.M.'s Standard
Hydrotest P	None	Design Code(s)	ASME B31.1
Local Control Panel	Adjacent to heater @ grade	**Branches**	OEM's Proprietary & Proven Design
Dilution Air Blowers	Two - OEM Standard	Duct Size, OD/ ID	NA - Convection Section Dimensions
Air Heater(s)	O.E.M.'s Standard	Quantity	design by SCR System OEM
Ammonia Vaporizer(s	O.E.M.'s Standard	Material, ASTM	A106 GrB
Mixing Device	O.E.M.'s Standard	NPS / schedule	O.E.M.'s Standard
Filters/ Strainers	O.E.M.'s Standard	Corrosion Allowance	0.0625 in
AFCU Skid	O.E.M.'s Standard	**Manifolds**	OEM's Proprietary & Proven Design
Drain	O.E.M.'s Standard	Quantity	One (1) Assembly
Skid Piping	Dilutant: SA53, NH3 line 304SS	Material, ASTM	SA53B
Electrical Wiring	wiring terminated in PLC's @ skid e	NPS / schedule	O.E.M.'s Standard
Instrument Wiring	wiring terminated in PLC's @ skid e	Corrosion Allowance	0.125 in
spare		Terminal Type	Flanged; OEM Std Size

AMMONIA INJECTION SYSTEM (continued)

				Ftnt & Rev
Heat Sources:		**Ammonia Vaporizer**	**Air Heater**	
O.E.M.	- - -	t.b.d.	t.b.d.	
O.E.M. Model &/or Type-Size	- - -			
Heat Input	MMBTU/ hr			
Configuration	- - -			
Size, ODx T/Tx thickness	in			
Shell Material	ASTM			
Design Basis / T / P	- - - / °F / psig			
Element Power	V / Hz / ph			
Vessels:		**Ammonia Tank**		
O.E.M.	- - -	t.b.d.		
O.E.M. Model &/or Type-Size	- - -			
Configuration/ Size, ODx T/Tx thicknes	in			
Shell Material	ASTM			
Design Basis / T / P	- - - / °F / psig			

DILUTION AIR / INDUCED DRAFT FAN ASSEMBLIES

		Dilution Air Fan(s)			
Process Design Conditions:		**Design**	**Test Block**		
Mass Flow Rate	Lb/ hr				
Volumetric Flow Rate	ft3/ hr				
Density, @ operating T & P	Lb/ ft3				
Temperature	°F				
Static Pressure Rise	inH2O				
Fan Speed, max. allowable / actual	RPM	3600 / t.b.d.	3600 / t.b.d.		
Sound Pressure, allowable / guarantee	dBA	< 85 / t.b.d.	< 85 / t.b.d.		

Fan Design:		**OEM's Standard**	
O.E.M.; OEM Reference	- - -	t.b.d.; Later	
O.E.M. Model &/or Type-Size	- - -		
Arrangement	- - -		
Brake Horsepower (calculated)	HP		
Silencer Type / Manufacturer	- - -		
Damper Design:		**Not Applicable**	
O.E.M.; OEM Reference	- - -		
O.E.M. Model &/or Type-Size	- - -		
Materials	- - -		
Bearings	- - -		
Motor Design:		**OEM's Standard**	
O.E.M.; OEM Reference	- - -	t.b.d.; Later	
O.E.M. Model &/or Type-Size	- - -		
Motor Type	- - -		
Frame Spec / Power	- - -/ HP		
Local Power	V/ Hz/ ph		

Owner:	**Lone Star NGL**	*Owner Ref.:*	**300-HR-001**	*Type:*	**Vertical Cylindrical, Single Cell**
Purchaser:	S&B Engineers and Constructors, Ltd.	*Purch. Ref.:*	C-1498	*Unit:*	Train 3
Manufacturer:	***TULSA HEATERS INC.***	***THI** Ref.:*	***P13-8431A***	*Site:*	***Mont Belvieu***

Ftnt & Rev

HOT FLUE GAS ZONE

System / Component Definition

System Design =	100%	No. of ID Fans =	1
HX/ RX Design =	0%	No. of hot fg ducts =	0
Fan Design =	115%	No. of cold fg ducts =	0

Case A Design Duty - Hot Oil Only — Design FG Flow = 169,013 Lbm/ hr

Case B Design Duty - Hot Oil + Regen Gas — Design FG Flow = 210,702 Lbm/ hr

system component	component description (API Std560)	coeff. or L (--, ft)	w or id (ft)	depth (ft)	flow area (ft2)	A: mass flow (Lbm/ hr)	A: T (°F)	A: ρ (pcf)	A: μ (cp)	A: vel. (ft/s)	A: RE (- - -)	A: dP (inH2O)	A: outlet P	B: mass flow (Lbm/ hr)	B: T (°F)	B: ρ (pcf)	B: μ (cp)	B: vel. (ft/s)	B: RE (- - -)	B: dP (inH2O)	B: outlet P
Draft @ Arch	@ Arch					169,013						0.40	-0.4	210,702						0.40	-0.4
Conv. Coils	per THI					169,013						0.45	-0.8	210,702						0.64	-1.0
SCR						169,013						1.50	-2.3	210,702						1.87	-2.9
Uptake Entr.	flanged entrance	0.34	4.00	4.00	32	84,506	388	0.045	0.025	16	2E+4	0.01	-2.4	210,702	399	0.044	0.025	41	6E+4	0.08	-3.0
Upt. Dampers	streamlined object	1.50	4.00	4.00	32	84,506	388	0.045	0.025	16	2E+4	0.05	-2.4	210,702	399	0.044	0.025	41	6E+4	0.34	-3.3
Upt. Ducts	3 piece elbow	0.45	4.00	4.00	32	84,506	388	0.045	0.025	16	2E+4	0.02	-2.4	210,702	399	0.044	0.025	41	6E+4	0.10	-3.4
Stk Plenum	sudden expansion	0.51	9.00	9.00	81	169,013	388	0.045	0.025	13	3E+4	0.01	-2.4	210,702	399	0.044	0.025	16	4E+4	0.02	-3.5
HFG Takeoff	sudden contraction	0.20	2.00	6.00	12	84,506	388	0.045	0.025	44	4E+4	0.05	-2.5	105,351	399	0.044	0.025	55	5E+4	0.08	-3.5
Inlet Ex.Jt.	proprietary form	0.11	2.00	6.00	12	84,506	388	0.045	0.025	44	4E+4	0.03	-2.5	105,351	399	0.044	0.025	55	5E+4	0.04	-3.6
ID Fan	Design SP					169,013	388	0.045	0.025			-3.1	0.6	210,702	399	0.044	0.025			-4.3	0.7
Discharge	sudden expansion	0.49	3.50	5.75	20	169,013	388	0.045	0.025	52	6E+4	0.18	0.4	210,702	399	0.044	0.025	66	7E+4	0.28	0.4
Transition	gradual contraction	0.1	6.67		35	169,013	388	0.045	0.025	30	4E+4	0.01	0.4	210,702	399	0.044	0.025	38	6E+4	0.01	0.4
Stack	draft gain	20.0	6.67		35	169,013	388	0.045	0.025	30	4E+4	0.00	0.4	210,702	399	0.044	0.025	38	6E+4	0.00	0.4
Stack	friction & exit loss	20.0	6.67		35	169,013	388	0.045	0.025	30	4E+4	0.00	0.4	210,702	399	0.044	0.025	38	6E+4	0.00	0.4
Surplus Static Pressure:													**0.4**								**0.4**

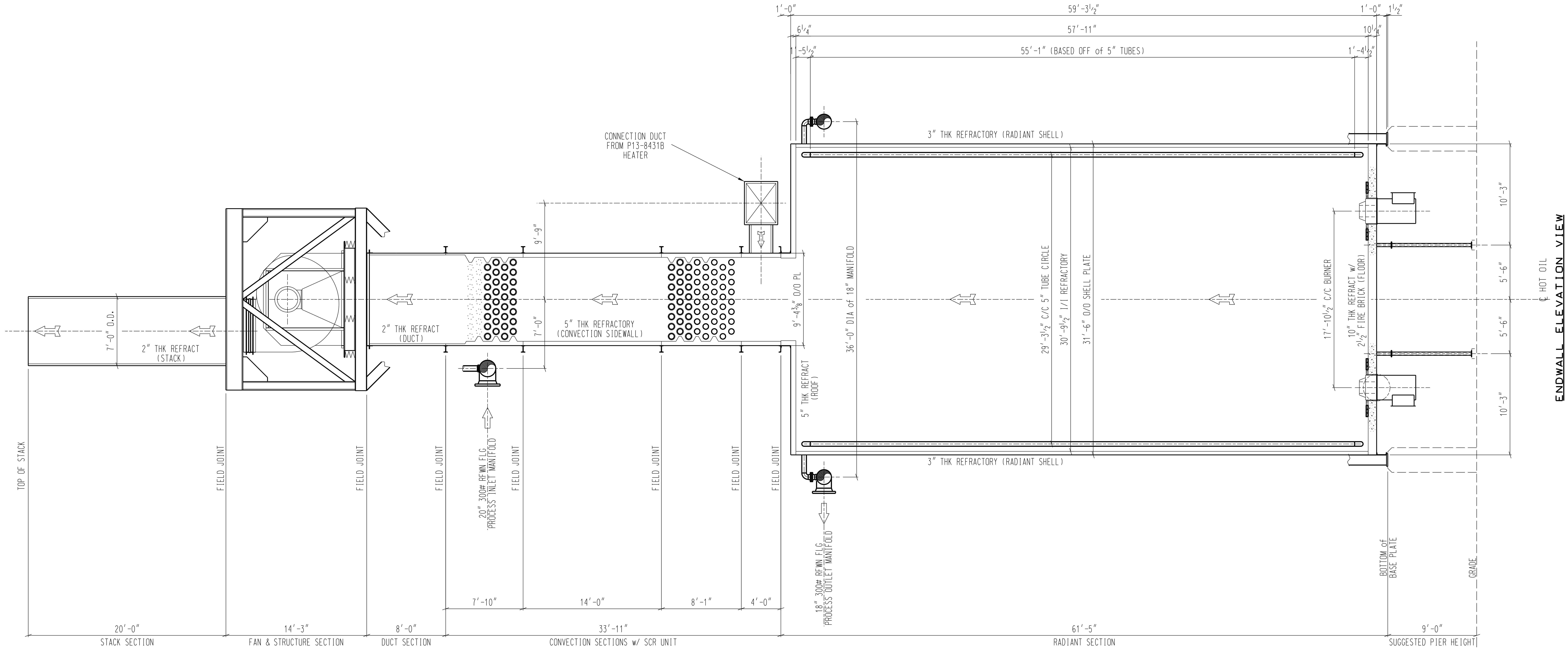
Notes

1) THI Design Basis = API std 560
(except as superceded by Project Specs)
2) Component ΔP's based on API 560
Annex F (Std560 Appendix E) methodology.
3) Component coefficients sourced from either
API 560 or Idelchik.
4) M&E&M BALANCES; Momentum & Energy
& Mass Balances
5)

revision	*date*	*description*	*by*	*chk'd*	*appv'd*

Lone Star NGL — S&B — THI TULSA HEATERS INC.

APH M&E&M BALANCES DATA SHEET
AMERICAN ENGINEERING SYSTEM of UNITS
P13-8431A- MEMBALds - Rev.00 ***Pg 1 of 1***



✳ - ALL DIMENSIONS ARE PRELIMINARY

Customer:

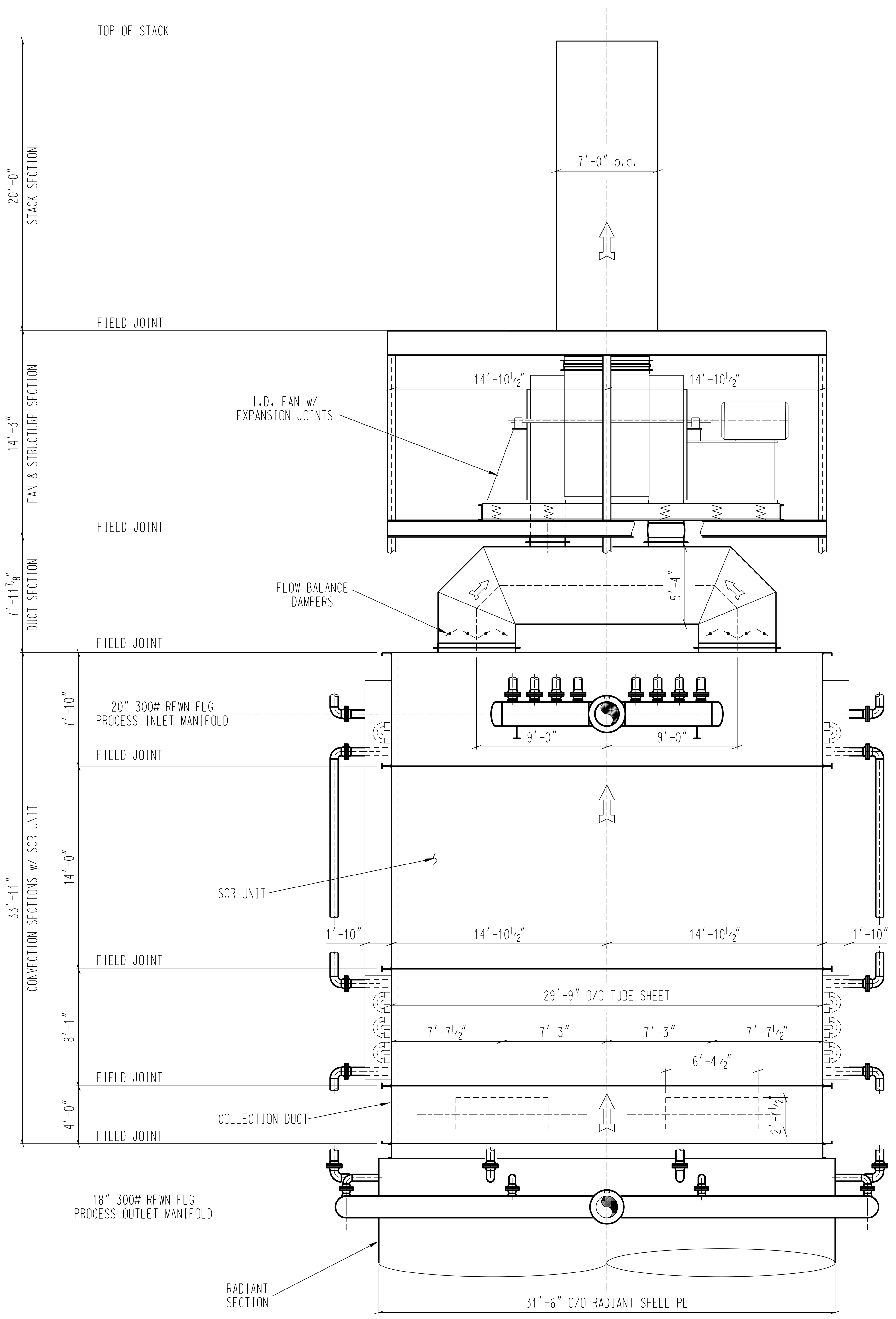
LONESTAR NGL

LOCATION : MT. BELVIEU, TX.
UNIT : TRAIN 3
SERVICE : HOT OIL HEATER
EQUIP. No. : 300-HR-001
PROPOSAL No. : P13-8431A

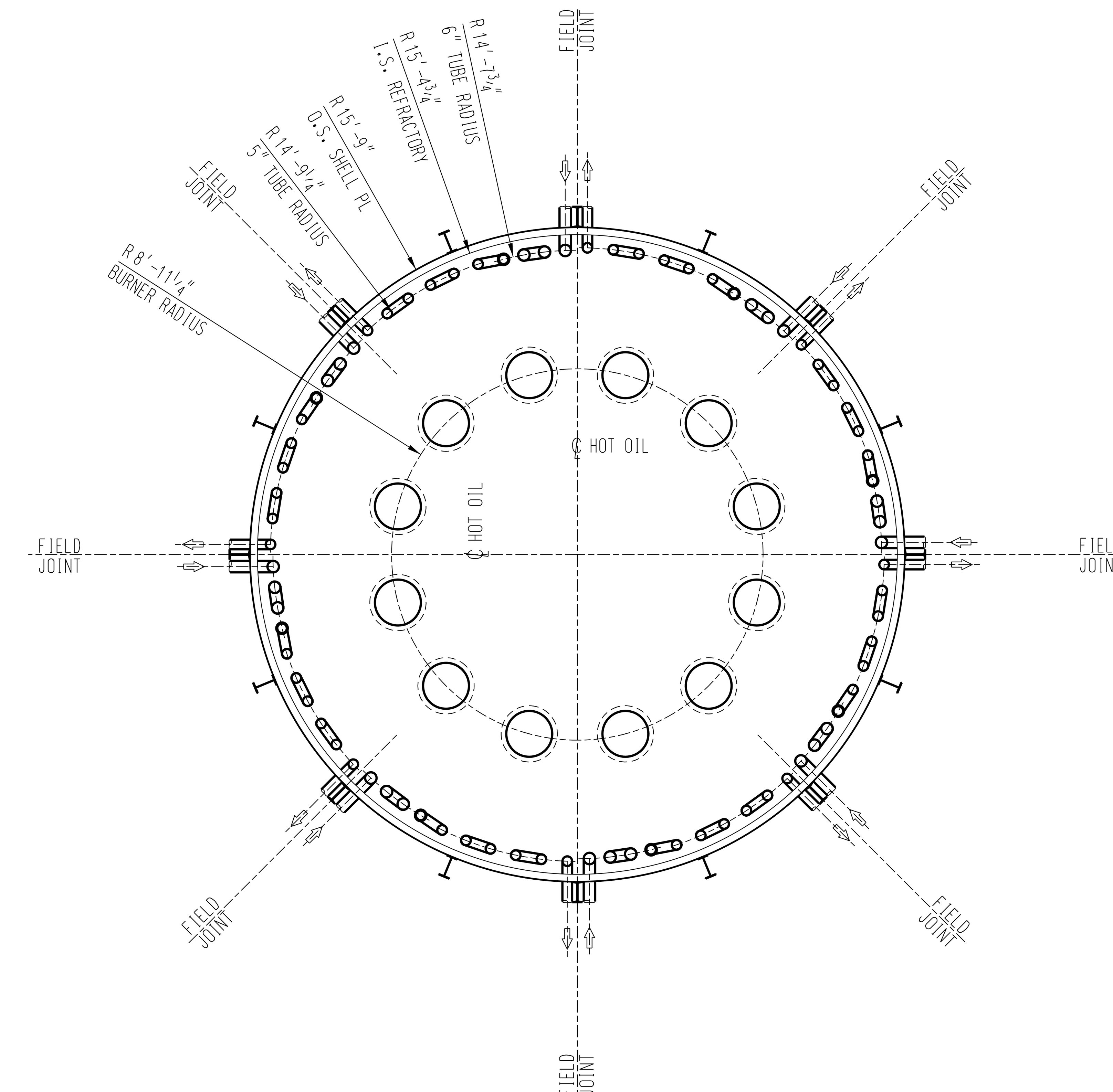
Rev.	Date	By	Revision Description

THI TULSA HEATERS INC.

Title			
GENERAL ARRANGEMENT ELEVATION			
Drawn By: ASW	Date: 03/08/13	Job No.: P13-8431	
Checked By	Date	Drawing No.: P13-8431-1A	Rev.: O



SIDEWALL ELEVATION VIEW



PLAN VIEW

@ RADIANT TUBES, BURNERS, & FLOOR

✳ - ALL DIMENSIONS ARE PRELIMINARY

Customer:

LONESTAR NGL

LOCATION : MT. BELVIEU, TX.
UNIT : TRAIN 3
SERVICE : HOT OIL HEATER
EQUIP. No. : 300-HR-001
PROPOSAL No. : P13-8431A

Rev.	Date	By	Revision Description
-			
-			
-			
-			
-			
-			

THI TULSA HEATERS INC.

Title: G.A. ELEVATION & PLAN VIEW		
Drawn By: ASW	Date: 03/08/13	Job No.: P13-8431
Checked By:	Date:	Drawing No.: P13-8431-1B Rev.: O

6. TECHNICAL - continued

6.3 Overview of Regen Gas Heaters - 300-HR-002; THI's P12-8431B

6.3.1 Technical Discussion

*The proposed heater is a single cell vertical cylindrical type with a serpentine coil configuration that satisfies the inquiry document requirements. In accordance with these documents, **THI** 's base offer for this heater provides the following performance and features:*

Process Design

- *Total process duty of 34.4 MMBtu/hr during Design operations,*
- *Process pressure drop of 22.6 psi for Design operations,*
- *Calculated thermal efficiency of 74.8% during Design operations,*

Combustion Design

- *ULTRA Low NOx burners (total of 4) providing at least 5:1 turndown,*
- *Flue gas emissions that comply with the rfq expectations (NOx of 0.01 lb/MMBtu),*
- *One conservatively sized convection mounted stack that will provide at least 0.1 inH2O draft at the arch during Design operations,*

Mechanical Design

- *Process Coils and Process Coil Supports per the rfq specifications,*
- *Radiant floor of stiffened 0.25 in CS plate; per data sheets & TABLE 3.2,*
- *Radiant sidewalls of stiffened 0.25 in CS plate; per data sheets & TABLE 3.2,*
- *Radiant arch of stiffened 0.25 in CS plate; per data sheets & TABLE 3.2,*
- *Radiant structure of typical CS shapes; per data sheets & TABLE 3.2,*
- *Convection sidewalls of stiffened 0.1875 in CS plate; per data sheets & TABLE 3.2,*
- *Convection tubesheets of 0.5 in CS plate; per data sheets & TABLE 3.2,*
- *Convection structure of typical CS shapes; per data sheets & TABLE 3.2,*
- *Self-supporting stack of 0.25 in (minimum) thick CS plate, per data sheets & TABLE 3.2,*
- *External coating(s) are per data sheets & TABLE 3.2,*
- *Internal coating is included per data sheets & TABLE 3.2,*

6.3.2 Fired Heater Data Sheets; Single Cell, Vertical Cylindrical
6.3.3 Mass, Energy & Momentum Data Sheet
6.3.4 Sketch; Single Cell, Vertical Cylindrical Heater Elevation
6.3.5 Sketch; Preliminary Plot Plan

Owner:	**Lone Star NGL**		Owner Ref.:	**300-HR-002**
Purchaser:	S&B Engineers and Constructors, Ltd.		Purchaser Ref.:	C-1498
Manufacturer:	***TULSA HEATERS INC.***		***THI*** Ref.:	***P12-8431B***
Service:	*Regen Gas*		Unit No:	*Train 3*
Number:	*One*		Location:	*Mont Belvieu, TX*
Process Duty:	***34.40***	***MMBTU/ hr***	Heater Type:	***Vertical Cylindrical, Single Cell***
Total Duty:	***34.40***	***MMBTU/ hr***		***w/ Integral Convection Section***

Ftnt & Rev

PROCESS DESIGN CONDITIONS

Heater Section	- - -	***RADIANT***	***CONVECTION***		***TOTAL***
Operating Case	- - -	***Design***	***Design***		***Design***
Service	- - -	*Regen Gas*	*Regen Gas*		
Heat Absorption	*MMBTU/ hr*	***27.50***	***6.90***		***34.40***
Process Fluid	- - -	*HC*	*HC*		
Process Mass Flow Rate, Total	*Lb/ hr*	*92,630*	*92,630*		
Process Bulk Velocity (allow. / calc.)	*ft/ s*	*- - - / 59*	*- - - / 4*		
Process Mass Velocity (min./ calc.)	*Lb/ s ft2*	*- - - / 161*	*- - - / 102*		
Coking Allowance (dP calcs)	*in*				
Pressure Drop, Clean (allow. / calc.)	*psi*	*< -------* ***25*** */*	***23*** *------- >*		
Pressure Drop, Fouled (allow. / calc.)	*psi*	*< ------- /*	*------- >*		
Average Heat Flux (allowable)	*BTU/ hr ft2*				
Average Heat Flux (calculated)	*BTU/ hr ft2*	***10,870***			
Maximum Heat Flux (allowable)	*BTU/ hr ft2*				
Maximum Heat Flux (calculated)	*BTU/ hr ft2*	*19,570*	*19,120*		
Fouling Factor, Internal	*hr ft2 °F/ BTU*	*0.0015*	*0.0015*		
Corrosion or Erosion Characteristics	- - -				
Max. Film Temperature (allow. / calc.)	*°F*	*None / 578*	*None / 319*		
Inlet Conditions:					
Temperature	*°F*	***200***	***120***		
Pressure	*psig*	***650***	***651***		
Mass Flow Rate, Liquid	*Lb/ hr*		*92,630*		
Mass Flow Rate, Vapor	*Lb/ hr*		*0*		
Weight Percent, Liquid / Vapor	*wt%*		*100% / 0%*		
Density, Liquid / Vapor	*Lb/ ft3*		*28.52 /*		
Molecular Weight, Liquid / Vapor	*Lb/ Lbmole*		*/*		
Viscosity, Liquid / Vapor	*cp*		*0.079 /*		
Specific Heat, Liquid / Vapor	*BTU/ Lb °F*		*0.731 /*		
Thermal Conductivity, Liquid/Vapor	*BTU/hr ft °F*		*0.043 /*		
Surface Tension, Liquid	*dyne/ cm*				
Outlet Conditions:					
Temperature	*°F*	***520***	***200***		
Pressure	*psig*	***628***	***650***		
Mass Flow Rate, Liquid	*Lb/ hr*	*0*			
Mass Flow Rate, Vapor	*Lb/ hr*	*92,630*			
Weight Percent, Liquid / Vapor	*wt%*	*0% / 100%*			
Density, Liquid / Vapor	*Lb/ ft3*	*/ 2.71*			
Molecular Weight, Liquid / Vapor	*Lb/ Lbmole*	*/ 44.3*			
Viscosity, Liquid / Vapor	*cp*	*/ 0.017*			
Specific Heat, Liquid / Vapor	*BTU/ Lb °F*	*/ 0.689*			
Thermal Conductivity, Liquid/Vapor	*BTU/hr ft °F*	*/ 0.029*			
Surface Tension, Liquid	*dyne/ cm*				

revision	*date*	*description*	*by*	*chk'd*	*appv'd*

FIRED HEATER DATA SHEET

AMERICAN ENGINEERING SYSTEM of UNITS

P12-8431B- HTRds - Rev.00 ***Pg 1 of 7***

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COMBUSTION DESIGN CONDITIONS

Overall Performance:		RADIANT	CONVECTION		TOTAL
Operating Case	- - -	Design	Design		Design
Service	- - -	Regen Gas	Regen Gas		
Excess Air	mol%				15.0%
Calculated Heat Release (LHV)	MMBTU/ hr				45.99
Guaranteed Efficiency	HR%				**73.8%**
Calculated Efficiency	HR%				74.8%
Radiation Loss	HR%				1.5%
Flow Rate, Combustion Gen./ Imported	Lb/ hr	44,770	/ 0		44,770
Flue Gas Temperature Leaving Section	°F	**1,442**	**937**		
Flue Gas Mass Velocity	Lb/ sec ft2		0.553		

Fuel(s) Data:		Design	C2		
LHV	BTU/ scf	942	1,618		
LHV	BTU/ Lb	21,003	20,420		
P @ Burner	psig	30	30		
T @ Burner	°F	100	100		
MW	Lb/ Lbmole	17.01	30.07		
μ @ ??? °F	cp	- - -	- - -		
μ @ ??? °F	cp	- - -	- - -		
Atomizing Media		- - -	- - -		
Atom. Media P & T		- - -	- - -		
Components:					
N	wt%	- - -	- - -		
S	wt%	- - -	- - -		
Ash	wt%	- - -	- - -		
Ni	ppm	- - -	- - -		
Va	ppm	- - -	- - -		
Na	ppm	- - -	- - -		
Fe	ppm	- - -	- - -		
H2	mol%	0.00	0.00		
O2	mol%	0.00	0.00		
N2 + Ar	mol%	1.08	0.00		
CO	mol%	0.00	0.00		
CO2	mol%	0.00	0.00		
CH4	mol%	93.04	0.00		
C2H6	mol%	5.77	100.0		
C2H4	mol%	0.00	0.00		
C3H8	mol%	0.11	0.00		
C3H6	mol%	0.00	0.00		
C4H10	mol%	0.00	0.00		
C4H8	mol%	0.00	0.00		
C5H12	mol%	0.00	0.00		
C5H10	mol%	0.00	0.00		
C6+	mol%	0.00	0.00		
H2S	mol%	0.00	0.00		
SO2	mol%	0.00	0.00		
NH3	mol%	0.00	0.00		
H2O	mol%	0.00	0.00		
spare	mol%	0.00	0.00		

Burner Design:			
OEM	- - -	Callidus, Zeeco or John Zink	
Type	- - -	BACT - Best Available Combustion Technology	
Quantities	- - -	4	Burners
Model No.1	- - -	TBA	Cylindrical
Model No.2	- - -	None	
Windbox	- - -	yes ...	w/ opposed blade registers
Location	- - -	Floor ... 4.39	ft. diameter burner circle
Pilot Design:			
Type	- - -	Continuous	Self-Inspirating
Model	- - -	TBA	
Ignition	- - -	Electric	requires elec.ign.system
Heat Release	- -	> 90,000 BTU/ hr on ...	Design RFG

Burner Performance:				
Minimum Heat Release	MMBTU/ hr	2.64		
Design Heat Release	MMBTU/ hr	11.50		
Maximum Heat Release	MMBTU/ hr	13.22		
Burner Turndown	Max:Min	5.00		
Volumetric Ht. Release	BTU/ hr ft3	6,670		
Draft @ Arch	inH2O	0.30		
Draft @ Burner	inH2O	0.71		
Combustion Air T @ Burner	°F	60		
Flue Gas T @ Burner	°F	1,250		
Guaranteed Emissions:		**<-- Combined -->**		
Basis of Guarantee	- - -	LHV Basis,3% O2 Dry		
NOx Emissions	lb/MMBtu	0.010		[C]
SOx Emissions	- - -	no quote		
CO Emissions	lb/MMBtu	0.030		
UHC Emissions	lb/MMBtu	0.030		
VOC Emissions	lb/MMBtu	0.030		
SPM10 Emissions	lb/MMBtu	0.025		
Noise Emissions	dBA @ 3ft	85.0		[D]

Special Burner Features &/ or Services:	
Reed Wall	None
Pilot Detection	Ionization Rod
Main Detection	UV Scanner
Burner Test	Yes; per Attachment A
CFD/ CF Models	None / None

Clearances:		Vertical				Horizontal	
... for Gas Firing:		**Minimum**	**Calculated**			**Minimum**	**Calculated**
... from burner CL ...		per Std 560	per THI Design			per Std 560	per THI Design
to Tube CL	ft	**31.00**	**43.22**	to Tube CL	ft	**4.39**	**5.31**
to Refractory	ft	31.00	40.30	to Refractory	ft	n / a	n / a

PRESSURE PARTS DESIGN

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Coil Design:		**RADIANT**	**RADIANT**	**SHIELD**	**CONVECTION**	
Service	- - -	Regen Gas	Regen Gas	Regen Gas	Regen Gas	
Design Basis for Tube Temperature	- - -	API Standard 530	API Standard 530	API Standard 530	API Standard 530	
Design Basis for Tube Wall Thickness	- - -	API Standard 530	API Standard 530	API Standard 530	API Standard 530	
Design Life	hr	100,000	100,000	100,000	100,000	
Design Pressure (elastic / rupture)	psig	**715 / 715**	**715 / 715**	**715 / 715**	**715 / 715**	
Design Fluid Temperature	°F	520	520	200	200	
Design Temperature Allowance	°F	25	25	25	25	
Design Corrosion Allowance (tubes/fitting	in	0.125 / 0.125	0.125 / 0.125	0.125 / 0.125	0.125 / 0.125	
Maximum Tube Temperature (clean)	°F	602	545			
Maximum Tube Temperature (fouled)	°F	636	579	343	343	
Design Tube Temperature	°F	**661**	**604**	**360**	**360**	
Inside Film Coefficient	BTU/ hr ft2 °F	397	219	186	186	
Weld Inspection	RT or Other	100 of 100%	100 of 100%	100 of 100%	100 of 100%	
Weld Heat Treatment	s.rel., t.stab. or none	None	None	None	None	
Hydrostatic Test Pressure	psig	per API	per API	per API	per API	
Coil Arrangement:		**Vertical**	**Vertical**	**Horizontal**	**Horizontal**	[F]
Coil Type	- - -	Serpentine	Serpentine	Serpentine	Serpentine	
Tube Material (pipe or tube spec)	ASTM	A106 GrB	A106 GrB	A106 GrB	A106 GrB	
Supplementary Mfg Requirements	ASTM	None	None	None	None	
Tube Outside Diameter	in	4.500	5.563	5.563	5.563	
Tube Wall Thickness (aw)	in	0.337	0.375	0.375	0.375	
Number of Cells (radiant or convection)	- - -	1	1	1	1	
Number of Flow Passes	- - -	2	2	2	2	
Number of Tubes per Row	- - -			4	4	[F]
Overall Tube Length	ft	37.67	37.34	16.95	16.95	
Effective Tube Length / Tube Circle Dia.	ft	39.00 / 15.01	39.00 / 15.01	15.20	15.20	
Number of Bare Tubes	- - -	**18**	**30**	**12**		
Total Exposed Surface	ft2	827	1,704	266		
Number of Ext.Surf. Tubes	- - -				**10**	[F]
Total Exposed Surface	ft2				1,138	
Tube Spacing (horizontal / tube centers)	in	/ 12	/ 15 / 10	10 / 10	10 / 10	
Tube Spacing (horizontal to refractory)	in	6	8	5	5	
Coil Fittings:		**Regen Gas**	**Regen Gas**	**Regen Gas**	**Regen Gas**	
Fitting Type	- - -	LR 180° U-Bends	LR/SR 180°	SR 180° U-Bends	SR 180° U-Bends	
Fitting Material	ASTM	A234 WPB	A234 WPB	A234 WPB	A234 WPB	
Supplementary Mfg Requirements	ASTM	None	None	None	None	
Fitting Outside Diameter	in	4.500	5.563	5.563	5.563	
Fitting Wall Thickness (aw ~~/ mw~~)	in	0.337	0.375	0.375	0.375	
Fitting Location	internal or external	Internal	Internal	External	External	
Tube Attachment	welded or rolled	Welded	Welded	Welded	Welded	
Coil Terminals:		**Outlet**			**Inlet**	
Terminal Type	beveled or flanged	Flanged			Flanged	
Flange Material	ASTM	A105			A105	
Supplementary Mfg Requirements	ASTM	None			None	
Flange Size and Rating	NPS/ ASME	4" NPS / 600 #			5" NPS / 600 #	
Flange Type	RFWN or RTJ	RFWN			RFWN	
Location	- - -	Radiant Roof			Terminal End	
Extended Surface:				**CONVECTION**	**CONVECTION**	
Service	- - -			Regen Gas	Regen Gas	
Fin or Stud Row Number	starting @ bottom			Row 1	Rows 2 - 3	
Ext. Surface Type	seg.fins, solid fins, studs			Solid Fins	Solid Fins	
Fin/Stud Material	- - -			C.S.	C.S.	
Fin/Stud Dimensions	H x T, in			0.5 x 0.06"	0.5 x 0.06"	
Fin/Stud Density	fin/ in or stud/ plane			3 fins/in	4 fins/in	
Maximum Fin/Stud Temperature	°F			452	335	

PRESSURE PARTS DESIGN (continued)

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Crossovers:		**RADIANT**	**SHIELD**	**CONVECTION**		
Type, location / connections	- - -	**External**	/ **Flanged**	**None**		
Tube / Fittings Material	ASTM	A106 GrB	/ A234 WPB			
Tube & Fitting Outside Diameter	in	< ------- 4.500 ------- >				
Tube & Fitting Wall Thickness (aw / mw)	in	< ------- 0.337	/ 0.295 ------- >			
Manifold(s) Design Basis:		**ASME B31.3 - 2006 Edition**				
Design Life	hr	100000	Design Pressure	psig	715	
Corrosion Allowance	in	0.125				
Location	- - -	**Inlet**	**Outlet**			
Type	- - -	Log w/ Tee	Log w/ Tee			
Quantity	- - -	**One (1)**	**One (1)**			
Pipe Material	ASTM	A106 GrB	A106 GrB			
Tube Connection Type	extrusion, olet, etc.	Weld o let	Weld o let			
Manifold Terminals	beveled or flanged	8" 600# WNRF	8" 600# WNRF			

Process Design:									
Number of Flow Passes (Connections)	- - -	**2**		**2**					
Design Temperature Allowance / Temp	°F	25	/ 145	25	/ 545				
Connection Inside Diameter	in	4.813		4.813					
100% Flow Area, All Passes	in2	36		36					
Manifold Outside Diameter(s)	in	8.625		8.625					
Manifold Wall Thickness; aw	in	0.500		0.500					
Manifold Relative Size, % Coil FA	%	125%		125%					

Mechanical Design:					
Allowable Stress @ Dsn T (Table A-1)	psi	20000	18180		
Quality Factor	- - -	1	1		
Temperature Coef. (Table 304.1.1)	- - -	0.4	0.4		
Wall Thickness, Minimum	in	0.277	0.292		
Manifold Wall Thickness, % of Calc. Minimum		181%	171%		

COIL & MANIFOLD SUPPORTS DESIGN

Tube Supports:		**RADIANT**	**SHIELD**	**CONVECTION**	
Service	- - -	Regen Gas	Regen Gas	Regen Gas	
Location	Top, Bottom, Ends	**Top**	**Ends**	**Ends**	
Support Type	casting, tubesht, spring, etc.	casting	tubesheet	tubesheet	
Material	ASTM	A351 HK40	A283 Gr. C	A283 Gr. C	
Support Thickness	in		0.50	0.50	
Refractory Type and Thickness	- - -		ref. refractory	ref. refractory	
Anchor Material and Type	- - -		section below	section below	
Intermediate Guides & Supports:		**None**	**None**	**None**	
Location	- - -				
Guide/ Support Type	casting, spring, etc.				
Material	ASTM				
Spacing, average	ft				
Tube Guides:	Top, Bottom, Ends	**Bottom**	**None**	**None**	
Material	ASTM	A312 T310			
Manifold Supports:		**Outlet Manifold**		**Intlet Manifold**	
Material	ASTM	Carbon Steel		Carbon Steel	
Materials Design & Supply	- - -	THI		THI	
Location	Top, Bottom, Ends	As Required		As Required	
Support Type	roller, shoe, spring, etc.	TBA		TBA	
Number of Supports	- - -	TBA		TBA	

CASING / REFRACTORY SYSTEMS DESIGN

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Radiant Section Design:		**PLENUM**	**FLOOR**	**SHIELDED**	**ARCH**	
Total Refractory Thickness	in	**0.0**	**11.5**	**3.0**	**5.0**	
Hot Face Temperature (design)	°F		2,500°	2,300°	2,300°	
Hot Face Temperaure (calculated)	°F		1,242	1,099	1,442	
Hot Face Layer	in/ - - -	None	2.5/ HD Firebrick	1/ 8# CF Blanket	1/ 8# CF Blanket	
Back-Up Layer No.1	in/ - - -		9/ LW Castable	1/ 8# CF Blanket	1/ 8# CF Blanket	
Back-Up Layer No.2	in/ - - -		None	1/ 8# CF Blanket	3/ 8# CF Blanket	
Foil Vapor Barrier	in/ - - -		None	None	None	
Castable Reinforcement (SS Needles)	wt%		None	None	None	
Anchors / Tie Backs:	- - -		**None**	**Pins & Clips**	**Pins & Clips**	
Material	- - -			310 S.S.	310 S.S.	
Attachment	- - -			Welded	Welded	
Casing:						
Material	in/ ASTM		**0.250 / A36**	**0.250 / A36**	**0.250 / A36**	
Internal Coating	- - -		None	Required	Required	
External Temp, guaranteed / calculated	°F		150 / 145	150 / 146	150 / 148	
Comments / Clarifications	- - -	ref. Burner section	9' 0" min.elev.	w/o cfb wraps	w/ cfb wraps	
			Field Installed			

		SIDEWALLS		ENDWALLS		
Convection Section Design:		**SHIELD**	**FINNED**	**TUBESHEETS**	**HEADER BOXES**	
Total Refractory Thickness	in	**4.0**	**4.0**	**4.0**	**2.0**	
Hot Face Temperature (design)	°F	2,300°	2,300°	2,000°	2,300°	
Hot Face Temperaure (calculated)	°F	1,190	1,190	1,190	444	
Hot Face Layer	in/ - - -	1/ 8# CF Blanket	1/ 8# CF Blanket	4/ SLW Castable	2/ 8# CF Blanket	
Back-Up Layer No.1	in/ - - -	1/ 8# CF Blanket	1/ 8# CF Blanket	None	None	
Back-Up Layer No.2	in/ - - -	2/ 8# CF Blanket	2/ 8# CF Blanket			
Foil Vapor Barrier	in/ - - -	None	None	None	None	
Castable Reinforcement (SS Needles)	wt%	None	None	None	None	
Anchors / Tie Backs:	- - -	**Pins & Clips**	**Pins & Clips**	**V's**	**Pins & Clips**	
Material	- - -	310 S.S.	304 S.S.	310/304 S.S.	304 S.S.	
Attachment	- - -	Welded	Welded	Welded	Welded	
Casing:						
Material	in/ ASTM	**0.1875 / A36**	**0.1875 / A36**		**0.1875 / A36**	
Internal Coating	- - -	Required	Required		Required	
External Temp, guaranteed / calculated	°F	150 / 139	150 / 139		150 / 107	
Comments / Clarifications	- - -	w/o cfb wraps	w/o cfb wraps	304SS Ferrules	w/o cfb wraps	
	- - -	Water washing / cleaning lanes: none		of 0' - 0" height.	std. bolted assembly	

		FLUE GAS DUCTS		STACK(s)		
Stack & Uptakes Design:		**BREECHING**	**FG Duct**			
Quantity		**One**	**One**	< ------- **None** ------- >		
Type / Location	- - -	Full L / Conv	Above Conv.			
Length / Metal Outside Diameter (top)	ft/ ft	n/ a / n/ a	Varies			
Discharge Elev., minimum/ calculated	ft/ ft	n/ a / n/ a	n/ a			
Total Refractory Thickness	in	**3.0**	**2.0**			
Hot Face Temperature (design)	°F	2,300°	2,300°			
Hot Face Temperaure (calculated)	°F	937	937			
Hot Face Layer	in/ - - -	1/ 8# CF Blanket	1/ 8# CF Blanket			
Back-Up Layer No.1	in/ - - -	1/ 8# CF Blanket	1/ 8# CF Blanket			
Castable Reinforcement (SS Needles)		None	None			
Anchors / Tie Backs:	- - -	**Pins & Clips**	**Pins & Clips**			
Material	- - -	304 S.S.	304 S.S.			
Attachment	- - -	Welded	Welded			
Casing:						
Minimum Thickness/ Material	in/ ASTM	**0.1875 / A36**	**0.1875 / A36**			
Corrosion Allowance	in	None	None			
Internal Coating	- - -	Required	None			
External Temp, guaranteed / calculated	°F	150 / 150	150 / 150			
Comments / Clarifications	- - -					

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MECHANICAL / STRUCTURAL DESIGN BASIS

Refractory & Coatings Design:

Refractory Design	**150°F Casing Temperature** w/ Ambient Conditions of 3 MPH & 90°F	
Refractory Dryout	SHOP dryout = None // FIELD dryout (per ES -1-9) within 3 months of shipment is recommended.	
Coating, Internal	12 dftmil CTE (Coal Tar Epoxy) on SP-6 Surface	
Coating, External	Technip Spec.: DH721033-000-JSS-2310-001-A, System CS-1	[E]

Applicable Standards:

API	Std 560; Fired Heaters for General Refinery	AISC	Specification for Design, ... Steel for Buildings
API	Std 530; Calc. of Heater Tube Thickness ...	AWS	D 1.1; Structural Welding Code
ASME	B31.3, Chemical Plant and ... Piping	ASTM	tube/ smls pipe/ fitting spec's noted herein
ASME	Sections I, II, VIII; B&PV Code	ASTM	refractories per C27, C155, C401 & C612
ASME	Section V; Non Destructive Examination	NFPA	NFPA 70; National Electrical Code

Wind Design:		**Seismic Design:**	
Spec. or Standard	ASCE 7-10	Spec. or Standard	ASCE 7-10
Velocity/ Imp. Factor	150 mph / 1	Zone/ Imp. Factor	D / 1.25
Site Exposure	"C"	spare	
Physical Design:		**Site Design Basis:**	
Plot Limitations	None	Site Elevation	69 ft AMSL
Tube Limitations	None	Stack Design T	105 °F
Firebox Pressure	Negative, per Std 560	FG Discharge El.	
		Area Classification	Class 1, Division 2, Groups C & D

MAJOR SUBSYSTEMS & ACCESSORIES

Major Subsystems:		**Major Accessories:**		
Burner Management	Included in base pricing	Casing/ Tube Seals	8	TubeSox; Radiant & Conv.
Burner Piping	Included Burner - Heater Edge	Observation Doors	4	5"x 9" w/o glass
Forced/ Ind. Draft	Induced Draft Fan Included	Observation Doors	None	
Air Preheat System	None in job scope	Observation Doors	None	
NOx Reduction Sys.	SCR Package Included	Access Doors	2	Std 24" x 24"
FBox Purge Fan	None in job scope	Access Doors	None	
FBox Purge Eductor	None in job scope	Tube Pulling Doors	2	Std 18" x 24"
ACWarning Lights	None	Pressure Relief Doors	None	
Painter's Trolley	None	spare	None	

Casing Penetrations			**Pressure Part Penetrations**		
Firebox Purge/ Snuff	2	2"NPS 150# RFWN	Coil TSTC's, Radiant	1	TSTC's / pass
CA Temperature	None		Coil TSTC's, Convection	0	
CA Pressure	None		Process TI conn's	2	1.5"NPS 600# RFWN's/ pass
FG Temperature	4	1.5"NPS 150# RFWN	Process PI conn's	None	
FG Pressure	10	2"NPS 3000# Coupling	Velocity Steam conn's	None	
FG Composition (Sam	4	2"NPS 3000# Coupling	S/A Decoking conn's	None	
FG Composition (O2)	1	3"NPS 150# RFWN's	Vent / Drain conn's	None	
FG Composition (EPA	None		spare	None	

Dampers:	**Flue Gas Control / Tight S.O.**	**Uptake Ducts** quantity = 0	**Stack** quantity = 0
Location / Qty	Flue Gas Duct / 1		
Design	Multiple Blade, Opposed Acting		
Flow Closed	<3% Leakage		
Flow Open	44770 lb/hr @ 937°F/-0.27 inH2O		
Size, ID's	4 ft Long x 7 ft Wide		
OEM & Ref.	TBA		
Materials	S.S. Blades & Shaft / CS Housing		
Bearings	Self Aligning - Self Lubricated		
Operator	OEM Standard - Pneumatic		
Positioner	OEM Standard - 4-20 mA		
Instruments	Limit Switches - Open / Closed		

Sootblowers: None

MAJOR SUBSYSTEMS & ACCESSORIES (continued)

Proposed Ladders & Platforms

Proposal & Design Basis:

1) Construction: 100% Galvanized A36 CS per API Standard 560 / ISO 13705
2) Provisions for External Coating(s) / Painting: None, except as explicitly set forth in THI's proposal
3) Additional L&P's: can be provided per the basis set forth in Sections 8 & 9 of THI's proposal

Component	Qty	Width	Length	Arc	O.D.	Weight	Price
	(- -)	(ft)	(ft)	(°)	(ft)	(Lb)	(US$)
Radiant Platforms							
Hearth Platform	1	3.00	23.56	360	23.56	5,420	
						0	
Intermediate Platforms	0	3.00	23.56	360	23.56	0	
Ladder to Grade	1	3.00	13.00			430	
Stair to Grade	1	3.00	8.00			820	
						0	
Convection Platforms							
Conv. End Platforms	2	4.00	5.45			1,390	
Conv. Side Platforms	1	3.00	26.45			2,380	
						0	
Ladder to Hearth	1	3.00	47.68			1,290	
Intermediate Platforms	1	3.00	4.00			420	
Damper Platforms							
Operations Platform	1	3.00		270	7.00	930	
Ladder to Conv.	1	3.00	10.55			360	
Intermediate Platforms	0	3.00	4.00			0	
EPA Platform	1	3.00		270	7.00	930	
Ladder to Dmpr	1	3.00	37.00			1,030	
Intermediate Pltfm	1	3.00		90	7.00	330	
Totals for Proposed Platforms						**15,730**	

CLARIFICATIONS, FOOTNOTES & REVISIONS

Refractory Systems Abbreviations Key:

HD Firebrick = High Density Firebrick;
CF Blanket = Ceramic Fiber Blanket - Thermal Ceramics Kaowool or equivalent;
HTCF Blanket - High Temperature Ceramic Fiber Blanket - Thermal Ceramics Cerachem or equivalent.
CF Modules - Ceramic Fiber Modules - Thermal Ceramics Pyro-Fold M or equivalent.
V Block - Insulating Vermiculite Block - Thermal Ceramics TR-19 or equivalent.
1:2:4 LHV = Shop mix castable of 1:2:4 specification, 1:0:6 LHV = Shop mix castable of 1:0:6 spec.
CF Board = Ceramic Fiber Board - Thermal Ceramics Kaowool M Board or equivalent
LW Castable = Light Weight Castable - Thermal Ceramics Kaolite 2200 or equivalent
LWLI Castable = Light Weight Low Iron Castable - Thermal Ceramics Kaolite 2300LI or equivalent
SLW Castable = Super Light Weight Castable - Thermal Ceramics Kaolite 2000LI or equivalent

[A] Indicated guaranteed process pressure drop excludes process dP of Inlet and Outlet manifolds [A]
[B] During turndown operations, this heater may experience CO "breakthrough". This undesirable phenomena is a byproduc [B]
of low NOx burner design / low firebox temperatures that are unable to force the CO oxidation reaction to completion.
[C] From design to maximum heat release. [C]
[D] Sound Pressure Level. [D]
[E] Surface Preparation - Sandblast SSPC-SP-6 [E]
Primer: Inorganic Zinc, 2 - 3 mils DFT
Intermediate: Amine Epoxy, 2 - 3 mils DFT
Finish: Polyurethane, 2 - 3 mils DFT, Color: Gray FS 16440
[F] The top most row of fin tubes consists of only two (2) tubes. [F]

Owner:	**Lone Star NGL**	*Owner Ref.:*	**300-HR-002**	*Type:*	**Vertical Cylindrical, Single Cell**
Purchaser:	S&B Engineers and Constructors, Ltd.	*Purch. Ref.:*	C-1498	*Unit:*	Train 3
Manufacturer:	***TULSA HEATERS INC.***	***THI** Ref.:*	***P12-8431B***	*Site:*	***Mont Belvieu, TX***

Ftnt & Rev

HOT FLUE GAS ZONE

System / Component Definition

System Design =	100%	No. of ID Fans =	**1**
HX/ RX Design =	100%	No. of hot fg ducts =	**1**
Fan Design =	115%	No. of cold fg ducts =	**0**
FG Duct Dsn (ft/s) =	**20**		

Case 1: 100% Heater Duty w/ RFG & 60°F CA

Design FG (incl.leakage) =	44,770	Lbm/ hr
Stack Damper Bypass =	0	Lbm/ hr
Design FG to FG/CA HX =	44,770	Lbm/ hr

system component	**component description**	**coeff. or L**	**w or id**	**depth**	**flow area**	**mass flow**	**T**	**ρ**	**μ**	**vel.**	**RE**	**dP**	**outlet P**
	(API Std560)	(--, ft)	(ft)	(ft)	(ft2)	(Lbm/ hr)	(°F)	(pcf)	(cp)	(ft/s)	(- - -)	(inH2O)	
Draft @ Arch	@ Arch					44,770						0.30	-0.3
Conv. Coils	per THI					44,770						0.05	-0.4
Transition	gradual contraction	0.07	3.75	6.50	24	44,770	937	0.027	0.035	19	1E+4	0.00	-0.4
FG Duct	rect. Duct	7.00	3.75	6.50	24	44,770	937	0.027	0.035	19	1E+4	0.00	-0.4
90° Elbow(s)	3 piece elbow	0.42	3.75	6.50	24	44,770	937	0.027	0.035	19	1E+4	0.01	-0.4
FG Duct	rect. Duct	8.50	3.75	6.50	24	44,770	937	0.027	0.035	19	1E+4	0.00	-0.4
Damper	Streamlined Object	0.07	3.75	6.50	24	44,770	937	0.027	0.035	19	1E+4	0.00	-0.4
FG Duct	rect. Duct	18.50	3.75	6.50	24	44,770	937	0.027	0.035	19	1E+4	0.00	-0.4
Transition	sudden contraction	0.20	3.75	3.25	12	22,385	937	0.027	0.035	19	7E+3	0.01	-0.4
FG Duct	rect. Duct	12.00	3.75	3.25	12	22,385	937	0.027	0.035	19	7E+3	0.00	-0.4
90° Elbow(s)	3 piece elbow	0.42	3.75	3.25	12	22,385	937	0.027	0.035	19	7E+3	0.01	-0.4
FG Duct	rect. Duct	3.5	3.75	3.25	12	22,385	937	0.027	0.035	19	7E+3	0.00	-0.4
FG Inlet	sudden expansion	0.3	8.00	2.00	16	22,385	937	0.027	0.035	14	6E+3	0.00	-0.4
Surplus Static Pressure:													**-0.4**

Notes

1) THI Design Basis = ISO 13705 / Std 560
(except as superceded by Project Specs)
2) Component ΔP's based on ISO 13705
Annex F (Std560 Appendix E) methodology.
3) Component coefficients sourced from either
13705 / 560 or Idelchik.
4) M&E&M BALANCES; Momentum & Energy
& Mass Balances
5)

revision	*date*	*description*	*by*	*chk'd*	*appv'd*

APH M&E&M BALANCES DATA SHEET
AMERICAN ENGINEERING SYSTEM of UNITS

P12-8431B- APHBALds - Rev.00 ***Pg 1 of 1***

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* - ALL DIMENSIONS ARE PRELIMINARY

PROPRIETARY INFORMATION

The information and designs shown herein, including all patented and patentable features are the property of, proprietary and confidential to TULSA HEATERS, INC.. This document shall not be reproduced in whole or part, or disclosed to any third party without the express written consent of TULSA HEATERS, INC.. All copies of this document, printed or electronic, are null and void if modified or altered in any way. Only TULSA HEATERS INC. possesses the controlling document in its original state and shall govern over any copy, printed or electronic.

Customer:

LONESTAR NGL

LOCATION : MT. BELVIEU, TX.
UNIT : TRAIN 3
SERVICE : REGEN GAS
EQUIP. No. : 300-HR-002
PROPOSAL No. : P13-8431B

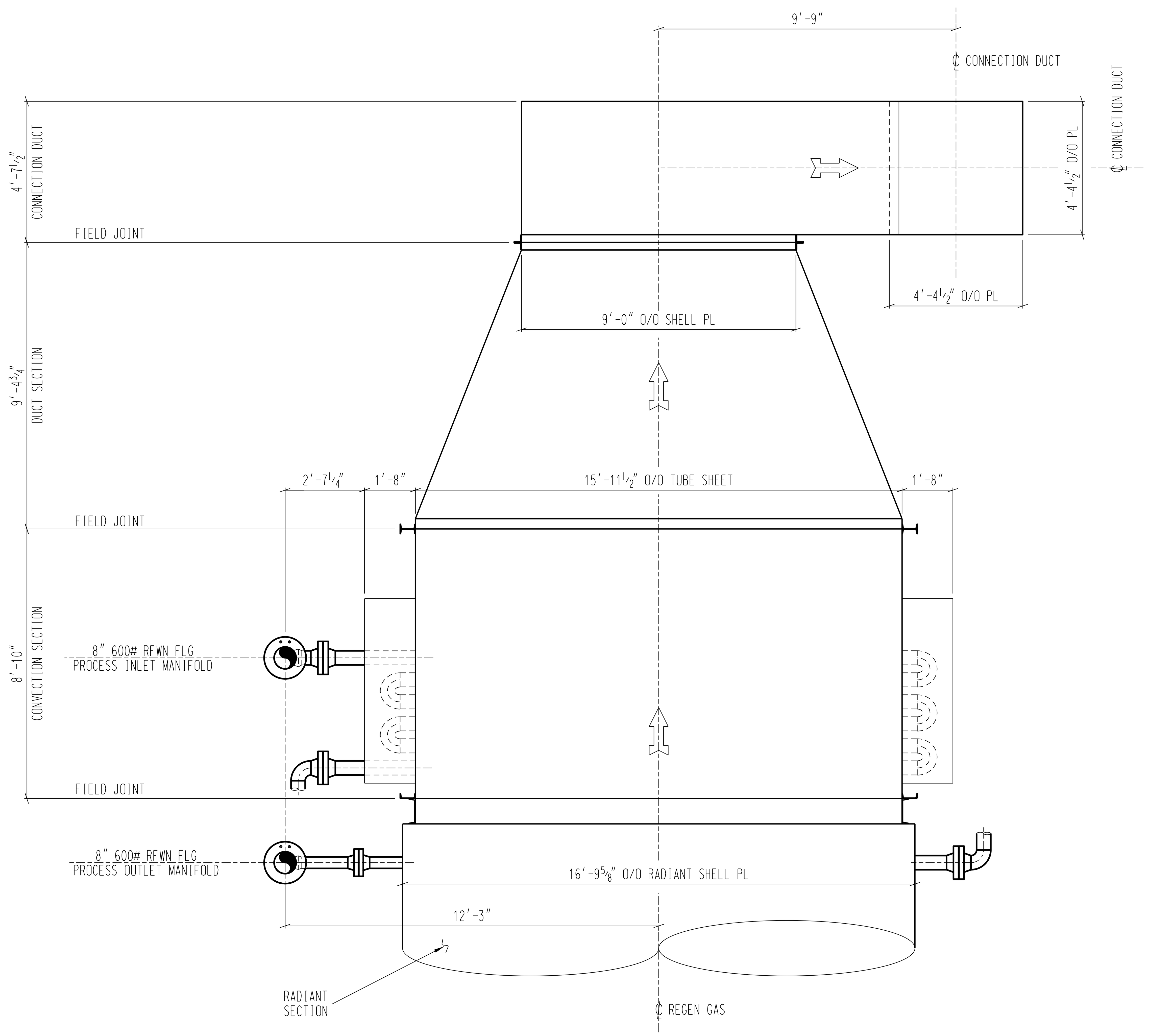
Rev.	Date	By	Revision Description

TULSA HEATERS INC.

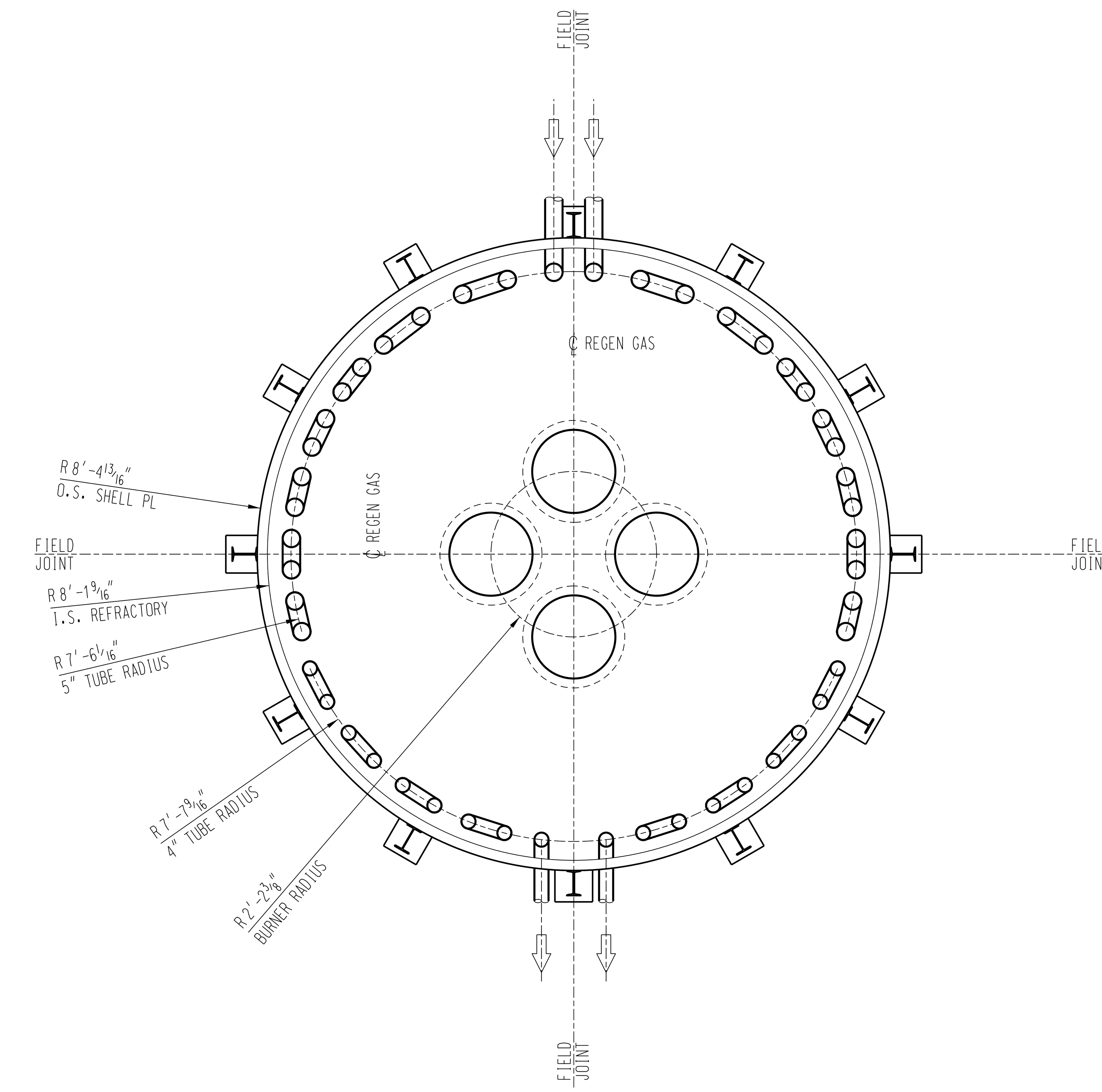
Title: GENERAL ARRANGEMENT ELEVATION

Drawn By	Date	Job No.:
ASW	03/08/13	P13-8431

Checked By	Date	Drawing No.	Rev.
		P13-8431-1C	0



SIDEWALL ELEVATION VIEW



PLAN VIEW

@ RADIANT TUBES, BURNERS, & FLOOR

✳ - ALL DIMENSIONS ARE PRELIMINARY

Customer:

LONESTAR NGL

LOCATION : MT. BELVIEU, TX.
UNIT : TRAIN 3
SERVICE : REGEN GAS
EQUIP. No. : 300-HR-002
PROPOSAL No. : P13-8431B

Rev.	Date	By	Revision Description

TULSA HEATERS INC.

Title: GENERAL ARRANGEMENT ELEVATION		
Drawn By: ASW	Date: 03/08/13	Job No.: P13-8431
Checked By:	Date:	Drawing No.: P13-8431-1D Rev.: O

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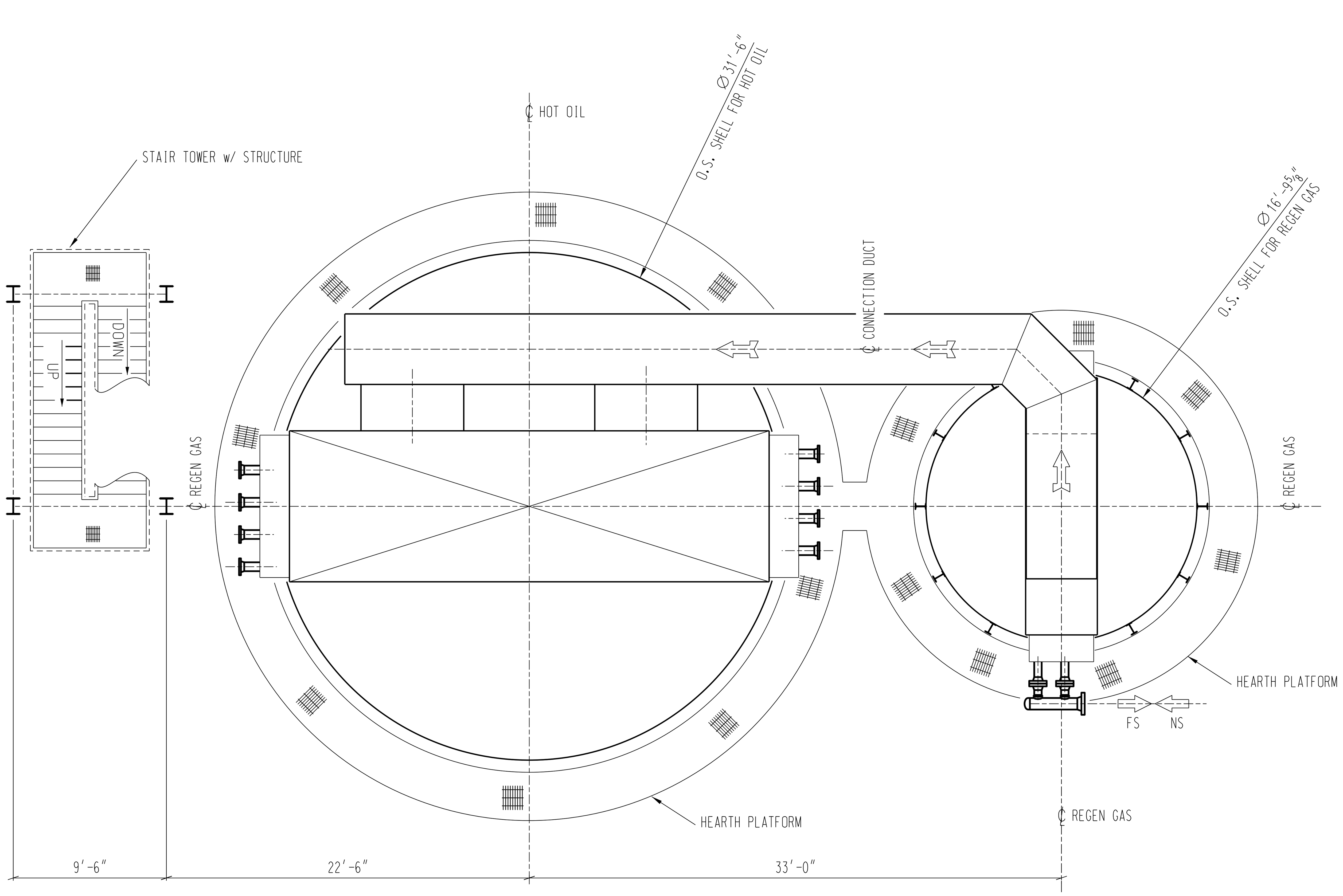
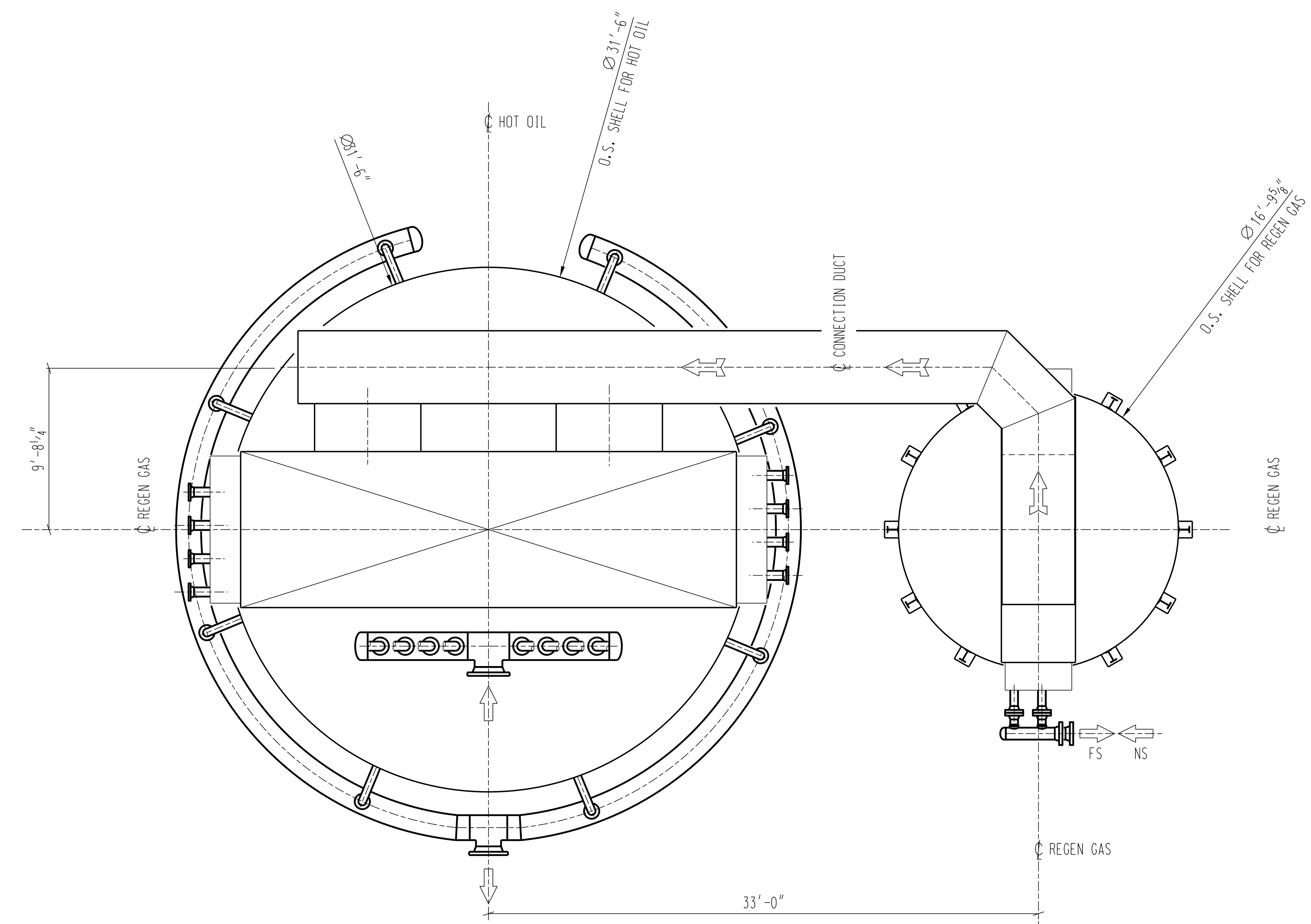


PLAN VIEW

(HOT OIL MANIFOLDS, FAN, STRUCTURE, & STACK NOT SHOWN FOR CLARITY)



PLAN VIEW

(PLATFORMS, STAIR TOWER, FAN, STRUCTURE, & STACK NOT SHOWN FOR CLARITY)

* - ALL DIMENSIONS ARE PRELIMINARY

Customer:

LONESTAR NGL

LOCATION : MT. BELVIEU, TX.
UNIT : TRAIN 3
SERVICE : HOT OIL HEATER & REGEN GAS
EQUIP. No. : 300-HR-001 & 300-HR-002
PROPOSAL No. : P13-8431A & B

Rev.	Date	By	Revision Description
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THI TULSA HEATERS INC.

Title			
G.A. PLAN VIEW			
Drawn By ASW	Date 03/08/13	Job No.: P13-8431	
Checked By	Date	Drawing No. P13-8431-1E	Rev. O

7. WARRANTIES & GUARANTEES

7.1 Warranty Basis

*7.1.1 Period; **THI** proposes to warrant the proposed systems for a period of eighteen (18) months after shipment or twelve (12) months after startup, whichever occurs first.*

*7.1.2 Scope; **THI** proposes to warrant all goods & equipment provided under contract.*

*7.1.3 Limitations; **THI**'s proposed terms are provided in the following Conditions of Sale.*

7.2 Mechanical Guarantees

*7.2.1 Materials; **THI** guarantees that all materials and components shall be new and of the Contract specified design (e.g., sizes, types, materials, etc.) and origin.*

*7.2.2 Coil(s); **THI** guarantees that the coil materials (tubes/pipe, fittings and flanges) will comply with the industry standards referenced by the Contract; in the absence of said references, the coil materials will comply with ISO 13704/ API Std 530 and ISO 13705/API Std 560.*

*7.2.3 Structure; **THI** guarantees that the stacks, ducts and supporting structures will be free of disfigurement & vibration, as defined by the contract and ISO 13705/API Std 560.*

7.3 Process Guarantees

*7.3.1 Duty; **THI** guarantees that the duty for each of the proposed heater(s) process coils will meet or exceed the duty figures set forth on **THI**'s data sheets at design operations.*

*7.3.2 Draft; **THI** guarantees that the proposed heater(s) will be capable of maintaining an arch draft of 0.10 inH2O at 100% design operations.*

*7.3.3 Pressure Drop; **THI** guarantees that the process pressure drop of the proposed heater(s) will not exceed the pressure drop figures set forth on **THI**'s data sheets.*

*7.3.4 Efficiency; **THI** guarantees that the thermal efficiency of the proposed heater(s) will meet or exceed the efficiency level set forth on **THI**'s data sheets at design operations.*

*7.3.5 Flux Rates; **THI** guarantees that the radiant average flux rates will not exceed 105% of the applicable average flux rates set forth on **THI**'s data sheets at design operations.*

7.4 Emissions Guarantees

*7.4.1 Noise Emissions; **THI** guarantees that noise emissions will not exceed 85 dBA @ 3 ft from heater casing during either natural draft or balanced draft operations.*

7.4.2 NOx Emissions; 300-HR-001 / P13-8431A
THI guarantees that NOx emissions will not exceed 0.01 lb/MMBtu @ design combustion conditions, throughout the specified operating temperature range of the SCR catalyst.

7.4.3 NOx Emissions; 300-HR-002 / P12-8431B
THI guarantees that NOx emissions will not exceed 0.01 lb/MMBtu @ design combustion conditions, throughout the specified operating temperature range of the SCR catalyst.

7.4.4 CO Emissions; 300-HR-001 / P13-8431A
THI guarantees that CO emissions will not exceed 0.03 lb/MMBtu @ design combustion conditions, from Design to Maximum heat release (and with a BWT in excess of 1,350 °F).

7.4.5 CO Emissions; 300-HR-002 / P12-8431B
THI guarantees that CO emissions will not exceed 0.03 lb/MMBtu @ design combustion conditions, from Design to Maximum heat release (and with a BWT in excess of 1,200 °F).

*7.4.6 Basis; the above **THI** guarantees are predicated on the burner OEMs' guarantees, and same are qualified by the Burner OEM's proposals included in Section 10.*

8. COMMERCIAL

8.1 Proposal Basis

*Except as explicitly stated to the contrary, the basis of **THI**'s proposal is the following:*

*8.1.1 **THI**'s Accountabilities*

1. ***THI** will provide professional support to the **Customer** throughout the project duration.*
2. ***THI** will provide the goods and/or services scope set forth in Sections 2, 3 & 10.*
3. ***THI** will provide the degree of shop fabrication / assembly established by Section 4.*
4. ***THI** will execute the project via the execution plan defined in Section 5.*
5. ***THI** will satisfy the rigorous technical & warranty requirements of Sections 6 & 7.*
6. ***THI** will adhere to the commercial terms (pricing & schedule) proposed in Section 8.*
7. ***THI** will execute the Contract, and manage **Customer**'s requests for change, in strict accordance with the Contract and the Commercial Terms of Sections 8 & 9.*

*8.1.2 **Customer**'s Accountabilities*

1. ***Customer** will provide **THI** a comprehensive PO within three (3) weeks of award; later PO issuances will delay **THI**'s procurement and design work, and yield a schedule slippage of one week for each and every week the PO is "late".*
2. ***Customer** will return the entire approved and/or commented GA Package to **THI** within one (1) week of their issuance; later GA Package returns will delay THI's procurement and design work, and yield a schedule slippage of one week for each and every week the GA Package is returned "late".*
3. ***Customer** will complete all significant changes within eight (8) weeks after award (ie, during the Engineering Phase / before Fabrication); changes after the Engineering Phase will increase **THI**'s costs and/or delay fabrication, which will be reflected in the scope change proposals submitted by **THI**'s Project Manager (ref. subsection 8.3).*
4. ***Customer** will facilitate **THI**'s contract execution, and **THI**'s management of change, in strict accordance with the Contract and the Commercial Terms of Sections 8 & 9.*

8.1.3 Additional Inclusions & Exclusions

1. ***THI**'s proposal is valid for thirty (30) days from the date of this offer.*
2. ***THI**'s pricing is firm.*
3. ***THI**'s pricing does NOT include for any local or state sales tax, nor the collection of any such tax. This includes state and local taxes on goods purchased in the state of Texas.*
4. ***THI**'s pricing - - except where specifically stated to the contrary - - does NOT include taxes (except payroll related taxes), duties, VAT's, and/or shipping charges.*
5. ***THI**'s resources are subject to prior sale; the proposed schedule will be confirmed at ToA.*
6. ***THI**'s proposal is predicated on the use of the Conditions of Sale set forth in Section 9.*
7. ***THI**'s proposal is a reflection of the scope and complexities of the **Customer**'s RFQ. Consequently, this proposal is somewhat lengthy. Nevertheless, it is the **Customer'**s responsibility for understanding **THI**'s proposal; failure to do so is at the **Customer'**s sole risk - **THI** can not provide relief for **Customer**'s errors, oversights or omissions.*

8.2 Pricing

8.2.1 Base Prices for Hot Oil Heaters - P13-8431A
Delivery Basis: Incoterms 2010 Ex Works, Loaded onto Truck, Tulsa (area), OK

1.	100-HR-001	Heater Base Price		(US$)	3,894,000
2.	Process Manifolds			(US$)	included
3.	Burner Management System			(US$)	included
4.	SCR System			(US$)	included
5.	Ammonia tank, instruments, pump skid & unloading stand			(US$)	438,205
6.	ID Fan & VFD			(US$)	included
7.	Burner Piping - Burner to Heater Edge			(US$)	included
8.	Flow Balancing Stations (manual valves / orifice flanges)			(US$)	included
9.	1 Day Burner Test at Burner OEM's facility			(US$)	included
10.	100-HR-001	Ladders & Platforms	52420 lb	(US$)	201,850
11.	100-HR-001	Stairtower	54335 lb	(US$)	181,480

8.2.2 Base Prices for Regen Gas Heater - P13-8431B
Delivery Basis: Incoterms 2010 Ex Works, Loaded onto Truck, Tulsa (area), OK

1.	100-HR-002	Heater Base Price		(US$)	1,091,000
2.	Process Manifolds			(US$)	included
3.	Burner Management System			(US$)	included
4.	Burner Piping - Burner to Heater Edge			(US$)	included
5.	1 Day Burner Test at Burner OEM's facility			(US$)	included
6.	100-HR-002	Ladders & Platforms	15730 lb	(US$)	60,580
	Total for above scope			(US$)	5,867,115

8.2.3 Common Items - Supplied for all heater and included in the price

1.	Domestic Shipping Preparation	(US$)	included
2.	Load-Out at FabShops	(US$)	included
3.	Erection & Commissioning Spares	(US$)	included

8.2.4 Optional Features for Both Heaters

1.	Add, for Freight & Insurance to Jobsite	(US$)	Cost + 0%
2.	Add, for incremental Platforms - up to 16 wks ARO	(US$/ lb)	3.85
3.	Add, for incremental Structure - up to 16 wks ARO	(US$/ lb)	3.40
4.	Add, for incremental Platforms - after 16 wks ARO	(US$)	Table 8.3
5.	Add, for incremental Structure - after 16 wks ARO	(US$)	Table 8.3
6.	Add, for ALL Other Changes in Contract Scope	(US$)	Table 8.3
7.	Add, for Shop Dryout of Refractory Systems	(US$)	upon request
8.	Add, for N2 Purge on Process Coils	(US$)	upon request
9.	Add, for Capital (2 Years) Spares	(US$)	upon request
10.	Add, for high-energy pilots w/ UV scanners	(US$)	101,800

8.2.5 Exclusions
1. *Local Instrumentation - unless otherwise noted*
2. *Interconnecting piping*
3. *Interconnecting wiring*
4. *Local civil work / piers*
5. *Orifice plates for flow balancing stations*

8.2.6 Specific Clarifications for Section 8.2
1. *All ladders, platforms, and stairtowers are quoted un-painted, galvanized.*

8.3 Provisions for Change

*Realizing that the proposed custom engineered heater system(s) have not been fully integrated into the **Customer**'s unit design, **THI** offers to provide post-award changes to the Contract scope per the following schedule & TABLE 8.3 (enclosed):*

8.3.1 Ladders & Platforms Changes

	Eng. & CADD	**Fabrication**	**Total**
1. Table 3.3 GA's, rev's 0&1	*Included*	*Included*	*per subsection 8.2*
2. Table 3.3 GA's, rev's 2+	*Table 8.3*	*120% Cost*	*E&C + 120%Fab*
3. Table 3.3 Fab Dwgs	*Table 8.3*	*120% Cost*	*E&C + 120%Fab*

8.3.2 All Other Materials and/ or Services Changes

	Eng. & CADD	**Fabrication**	**Total**
1. Table 3.3/PO Scope, rev's 0&1	*Included*	*Included*	*per subsection 8.2*
2. Additional Scope, rev's 0&1	*Table 8.3*	*120% Cost*	*E&C + 120%Fab*
3. Table 3.3/PO Scope, rev's 2+	*Table 8.3*	*120% Cost*	*E&C + 120%Fab*
4. Additional Scope, rev's 2+	*Table 8.3*	*120% Cost*	*E&C + 120%Fab*

Additional clarification of subsections 8.3.1 & 8.3.2:

- *a. Rev. 0 docs (per Table 3.3 / Contract Data) are included in **THI**'s base prices,*
- *b. **Customer** directed changes incorporated into Rev. 0 & 1 GA drawings will be be provided at 120% of fab costs and without Engineering or CADD charges,*
- *c. **Customer** directed changes incorporated into a Rev. 2 or higher GA drawings will be provided at 120% of fab costs plus Eng & CADD costs (per TABLE 8.3),*
- *d. **Customer** directed changes (via drawing markups, emails, telecons, etc.) to L&P's with "approved" drawing status will effectively void the "approved" status of ALL affected drawings, render such drawings unsuitable for material purchase and/or fabrication, and necessitate the resubmittal of ALL affected drawings to **Customer** for their appropriate review and "approval".*
- *e. **Customer** directed changes that simply revise rev.0 GA Drawings to reflect the accepted contract scope, will be provided at no charge, regardless of GA revision.*
- *f. **Customer** directed changes to L&P's that yield increased weights in ladders, platforms, stairs, supports to grade, supports to casing or other elevated anchor points, and/or platform lugs of any kind - that are in excess of the Contract's platform allotment - will be to the Customer's account and invoiced accordingly.*
- *g. All changes - including platform lugs - will be to the **Customer**'s account per 8.3.1.*
- *h. Additional documents are defined as any/all documents added to **THI**'s scope that exceed the documentation provisions of TABLE 3.3, and*
- *i. All changes are subject to the provisions of **THI**'s Conditions of Sale, Section 9*

STANDARD RATES for PRODUCT DESIGN REVISIONS

REVISION RATES for ALL "FIRM PRICE" CONTRACTS

Group 1 Documents:	Heater or WHRU (only)		Heater w/ APH &/or DeNOx		Comments
Issue Revision 0 doc's	0	US$ / set	0	US$ / set	incl. in Base Price
Issue Revision 1 doc's	0	US$ / set	0	US$ / set	incl. in Base Price
Issue Revision 2 doc's	750	US$ / set	1,250	US$ / set	billed as Adder
Issue Revision 3 doc's	1,250	US$ / set	2,250	US$ / set	billed as Adder
Issue Revision 4 doc's	1,750	US$ / set	3,250	US$ / set	billed as Adder
Issue Revision 5+ doc's	2,250	US$ / set	4,250	US$ / set	billed as Adder

Group 2 Documents:	Heater or WHRU (only)		Heater w/ APH &/or DeNOx		Comments
Issue Revision 0 doc's	0	US$ / sheet	0	US$ / sheet	incl. in Base Price
Issue Revision 1 doc's	0	US$ / sheet	0	US$ / sheet	incl. in Base Price
Issue Revision 2 doc's	350	US$ / sheet	350	US$ / sheet	billed as Adder
Issue Revision 3 doc's	600	US$ / sheet	600	US$ / sheet	billed as Adder
Issue Revision 4 doc's	850	US$ / sheet	850	US$ / sheet	billed as Adder
Issue Revision 5+ doc's	1,200	US$ / sheet	1,200	US$ / sheet	billed as Adder

Group 3 Documents:	Heater or WHRU (only)		Heater w/ APH &/or DeNOx		Comments
Issue Revision 0 doc's	0	US$ / document	0	US$ / document	incl. in Base Price
Issue Revision 1 doc's	750	US$ / document	1,250	US$ / document	billed as Adder
Issue Revision 2 doc's	1,250	US$ / document	2,250	US$ / document	billed as Adder
Issue Revision 3+ doc's	2,500	US$ / document	4,500	US$ / document	billed as Adder

Firm Price Clarifications:

1) Above noted document charges **do not include** costs of materials, labor and consumables required to execute change.
2) Charges accrue when documents are issued by THI; docs issued to "correct" a THI error will not be billed to Purchaser.
3) Group 1 Docs include: a) system data sheets, b) calculations, c) diagrams, d) QMS Docs and others per TABLE 3.3
4) Group 2 Docs include: a) GA Drawings, b) Detail Drawings and c) component data sheets and others per TABLE 3.3
5) Group 3 Docs include: a) final data books and others per TABLE 3.3
6) Data sheet pricing is based on use of THI's data sheets; Purchaser's sets may be used for Rev. 0 Adder of 5,000 US$
7) QMS documents include QIP's, WPR's, PQR's and any other "job specific" documents developed by THI.
8) spare

REVISION RATES for ALL "COST PLUS" CONTRACTS

Office Rate Basis:	Standard Rates	Overtime Rates	Holiday Rates	Comments
Billable Services; Mon - Fri	8.0 hrs / day	before 8/ after 5PM	ALL Fed. Holidays	
Billable Services; Sat & Sun	none	Saturday & Sunday	ALL Fed. Holidays	

Product Design Services:	Standard Rates		Overtime Rates		Holiday Rates		Comments
Engineering Services	200	US$ / hr	300	US$ / hr	400	US$ / hr	ALL Disciplines
CADD Services	175	US$ / hr	260	US$ / hr	350	US$ / hr	

Project Execution Services:	Standard Rates		Overtime Rates		Holiday Rates		Comments
Project Management Services	200	US$ / hr	300	US$ / hr	400	US$ / hr	
Procurement/Expediting Services	150	US$ / hr	225	US$ / hr	300	US$ / hr	
QMS/ Inspection Services	120	US$ / hr	180	US$ / hr	240	US$ / hr	
Administrative Assistant Services	100	US$ / hr	150	US$ / hr	200	US$ / hr	

Rev.07	22-Oct-08	Updated to reflect current costs	JTE	TLC	MPL
Rev. 06	8-Jul-06	Updated to reflect current costs	TLC	EVP	TBC
revision	date	description	by	chk'd	app'd

Job Specific Notes:

1) prices are firm thru contract completion
2) none
3) none

THI TULSA HEATERS INC.

TABLE 8.3: STANDARD RATES

PROPOSED PROVISIONS FOR CHANGE

THIStandard -Ratesds-06 **Page 1 of 2**

www.tulsaheaters.com ◆ info@tulsaheaters.com ◆ rfq@tulsaheaters.com ◆ TULSA HEATERS INC ◆ 1350 S. Boulder Ste 800 ◆ Tulsa, OK 74119 ◆ (918) 582-9918 ◆ (918) 582-9916 Fax

STANDARD RATES for DOMESTIC ONSHORE SERVICES

FIELD RATES BASIS

	Standard Rates	Overtime Rates	Holiday Rates	Comments
Normal Business Hours:				
Time of the Day	8:00 AM - 5:00 PM			local time
Days of the Week	Monday - Friday			excl. Sat or Sun.
Billable Field Services:				
on Weekdays	< first 8.0 hrs/ day	> 8.0 hrs/ day	ALL Fed. Holidays	Monday - Friday
on Weekends	< first 8.0 hrs/ day	> 8.0 hrs/ day	ALL Fed. Holidays	Saturday & Sunday
Billable Travel Time:				
on Weekdays	< first 8.0 hrs/ day	> 8.0 hrs/ day	ALL Fed. Holidays	Monday - Friday
on Weekends	< first 8.0 hrs/ day	> 8.0 hrs/ day	ALL Fed. Holidays	Saturday & Sunday
Billable Expenses:				
Travel Expenses	billed @ 100% cost	billed @ 100% cost	billed @ 100% cost	coach class
Living Expenses	billed @ 100% cost	billed @ 100% cost	billed @ 100% cost	std. accommodations

FIELD SERVICE RATES - - DOMESTIC ONSHORE SERVICES

	Standard Rates		Overtime Rates		Holiday Rates		Comments
Field Erection Advisor:							
on Weekdays	1,600	US$/ day	300	US$/ hr	400	US$/ hr	Monday - Friday
on Weekends	2,400	US$/ day	400	US$/ hr	400	US$/ hr	Saturday & Sunday
Training Services:							
on Weekdays	1,600	US$/ day	300	US$/ hr	400	US$/ hr	Monday - Friday
on Weekends	2,400	US$/ day	400	US$/ hr	400	US$/ hr	Saturday & Sunday
Start-Up/ Commissioning Advisor:							
on Weekdays	1,600	US$/ day	300	US$/ hr	400	US$/ hr	Monday - Friday
on Weekends	2,400	US$/ day	400	US$/ hr	400	US$/ hr	Saturday & Sunday
Technical Assistance:							
on Weekdays	1,600	US$/ day	300	US$/ hr	400	US$/ hr	Monday - Friday
on Weekends	2,400	US$/ day	400	US$/ hr	400	US$/ hr	Saturday & Sunday

Comments & Abbreviations:

1) Normal workday includes 1 hour lunch break
2) Weekend overtime (OT) is billed at Holiday rates
3) Applicable Area(s): ENTIRE United States of America
   ... Lower 48 states + Alaska + Hawaii
4) Any/ all safety training will be billed at standard rates.
5) Above rates are FIRM thru Warranty Period.
6) Rates reflect Net 30 day (ARI) payments.
7) ALL Fed. Holidays; all holidays formally recognized by the Federal Government of The USA.
8) spare

revision	date	description	by	chk'd	app'd
Rev. 08	9-Oct-08	Updated to reflect current costs	JTE	MPL	DPL
Rev. 07	12-Jun-06	Incorporated comments on Safety Training	TLC	MPL	DPL
Rev. 06	21-Apr-06	Updated to reflect current costs	TLC	MPL	DPL

Job Specific Notes:

1) prices are firm thru contract completion
2) none
3) none

THI TULSA HEATERS INC.

TABLE 8.3: STANDARD RATES
PROPOSED PROVISIONS FOR CHANGE

THIStandard -Ratesds-08 **Page 2 of 2**

www.tulsaheaters.com ◆ info@tulsaheaters.com ◆ rfq@tulsaheaters.com ◆ TULSA HEATERS INC ◆ 1350 S. Boulder Ste 800 ◆ Tulsa, OK 74119 ◆ (918) 582-9918 ◆ (918) 582-9916 (fax)

8.4 Modules Weights & Sizes

Later

8.5 Proposed Manufacturing Schedule

8.5.1 Schedule Basis
*In addition to the timely execution of **THI**'s and the **Customer**'s responsibilities, as previously set forth in subsections 8.1.1 and 8.1.2, **THI**'s proposed schedule is also predicated on the following:*

1. *The timely fulfillment of **THI**'s tubular order (i.e., the Mill meets their contracted schedule).*

2. *The complete fulfillment of **THI**'s tubular order (i.e., the Mill ships the contracted quantity). Recent shortages have created an "allocation" distribution of some critical pressure part components. Although **THI** has not been "shorted" on a pressure part order recently, it is possible that future pressure part supply shortfalls could create significant delays in product completion. Time contingencies for pressure part shortages are NOT included in the proposed schedule.*

3. ***THI** reserves the right to adjust completion dates to reflect delays in shipment of critical path materials. Recently, because of market forces beyond **THI**'s control, said pipe & tube suppliers have occasionally changed contracted coil materials ship date without **THI**'s concurrence or knowledge.*

4. ***THI**'s "QMS" approved fabshops current backlog; the preliminary schedule must be confirmed by **THI** at time of order.*

8.5.2 Major Milestones

1. Order Tubulars from pipe mill	*(wks ARO)*	*2*
*2. Issue GA Package to **Customer***	*(wks ARO)*	*6*
3. Receive Approved GA's from Customer	*(wks ARO)*	*8*
*4. Issue Fab Drawings to **THI**'s FabShop*	*(wks ARAD)*	*10*
*5. Heater Shipment from **THI**'s FabShop*	*(wks ARAD)*	*42*

ARO = After Receipt of Order
ARAD = After Receipt of Approved Drawings

9. CONDITIONS of SALE

Should THI be awarded the contract for this project, the S&B Engineers and Constructors, LTD. ("S&B") General Terms and Conditions (2/15/13) will apply, as amended by the comments in Section 2 of this proposal, and supplemented by the following terms.

9.1 Contract - Entire Agreement

*These Conditions of Sale, **THI**'s proposal, and the **Customer**'s Inquiry, as accepted and modified by **THI** within Section 2, shall constitute the final and entire agreement between **THI** and **Customer** (the "Contract"), and no agreement or other understanding purporting to add to or modify the terms and conditions herein shall be binding to either party unless agreed to by both parties.*

9.2 Title - Risk of Loss

Per clause 26 of S&B T&C's.

9.3 Contract Basis

***THI** will require a conventional PO, as long as jurisdiction remains within the USA, issued within three weeks of the PO Date (and prior to **THI**'s issuance of the GA Package).*

9.4 Project Cancellation

*Following is **THI**'s proposed cancellation schedule:*

Major Activity	***Applicable Period***	***Cost to Cancel***
• Job Kick-Off	*up to 2 wks ARO*	*5% of PO Value*
• Purchase Coil	*up to 3 wks ARO*	*30% of PO Value*
• Issue GA Package	*up to 6 wks ARO*	*35% of PO Value*
• Purchase Eng. Components	*up to 7 wks ARO*	*40% of PO Value*
• Issue Fab Drawings	*up to 8 wks ARAD*	*45% of PO Value*
• Purchase Casing	*up to 9 wks ARAD*	*60% of PO Value*
• Begin Fabrication	*up to 12 wks ARAD*	*65% of PO Value*
• Begin Refractory	*up to 16 wks ARAD*	*75% of PO Value*
• Begin Coil Fab.	*up to 20 wks ARAD*	*80% of PO Value*
• Begin Assembly	*up to 30 wks ARAD*	*85% of PO Value*
• Begin Final NDE	*up to 36 wks ARAD*	*90% of PO Value*

9.5 Acceptance

*Contracts arising out of this proposal shall not be binding upon **THI** until accepted and acknowledged by an authorized officer of **THI** or his designee.*

9.6 Provisions for Scope Definition

*At some appropriate time before a decision is made, and at no cost to either **Customer** or Owner, **THI** proposes to meet with the **Customer**'s and **Owner**'s team members to review this project in exacting detail. In **THI**'s view, this meeting should occur just prior to a contract award so that all parties could further their understanding of the project's scope and details. If executed as a pre-award meeting, please note that **THI** would incorporate the PAM Minutes into our kick-off meeting notes and discussion (except as superseded by more recent changes).*

9. CONDITIONS of SALE - continued

9.7 Provisions for Change

Customer *may, by written request, request* ***THI*** *to execute scope changes within the general framework of the contract. If* ***Customer****'s change request causes an increase in* ***THI****'s costs, or will cause an increase in the contract duration,* ***THI*** *shall quote such affects or advise Customer of a pending "scope change proposal" that is under development within ten (10) working days of* ***Customer****'s request, and similarly,* ***Customer*** *shall have ten (10) working days to provide* ***THI*** *written authorization to proceed or notification to the contrary. Failure to respond to the other party within the ten day window is grounds for:*

1. ***Customer*** *to expect the requested change without cost (if* ***THI*** *fails to provide a scope change proposal or notification that same under development), or*
2. ***THI*** *to expect the change proposal was declined (if* ***Customer*** *fails to respond).*

THI *proposes to provide all material and engineering changes as set forth in Section 8.*

9.8 Progress Payment Terms

THI*'s proposal is based on the application of the following measurable milestone payments that yield almost a "break even" cash flow for THI:*

• 10% Upon Issuance of General Arrangement Package	Net 30 Days ARI
• 20% Upon Issuance of Detail Drawings Package to Fab Shop	Net 30 Days ARI
• 40% Upon Receipt of Tubes and Return Bends	Net 30 Days ARI
• 28% Upon Notification of Ready to Ship	Net 30 Days ARI
• 2% Upon Completion of Vendor Data (as required by PO)	Net 30 Days ARI

Please note that THI will charge interest @ 1.50% of the invoice value per month to all past due accounts.

9.9 Force Majeure

THI *shall not be liable for any delay or impairment of performance resulting in whole or in part from strikes, labor disruptions, riots, shortages of transportation, controversy, wars, terrorism, acts of God, weather, fires, explosions, embargo delays, government (in)actions, or shortages of labor, fuel, equipment, etc., changes of law, or any other circumstance or causes beyond the control of* ***THI****.*

9.10 Data Rights - Confidentiality

The information contained within this proposal is the exclusive confidential property of THI, is is furnished solely for the purpose of evaluation by the Customer and/or the Customer's Client (ie, the Owner Operator), and shall be retained in strict confidence by said recipient(s). All copies of this proposal shall remain the property of THI and shall be promptly returned to THI upon request.

9.11 Process Design Calculations

Most of THI's process design software is proprietary, in that the programs were internally developed by THI and are the direct result of THI's investment in time, effort and knowledge. Consequently, such software will not be disclosed to any third party. Included in this category are:

- *Thermal Rating Programs; for virtually all firing combinations.*
- *Two-Phase Model; enhanced SRK EOS pseudocomponent modeling program.*
- *Cracking Model; enhanced Two-Phase Model w/ coking & cracking modules.*

However, industry standard design practices and hardcopy outputs (from the above) are available for distribution to Customer and/or Others for their information and review.

9. CONDITIONS of SALE - continued

9.12 Approved Suppliers

THI's proposal is based on the subcontracting of all material supply and fabrication, and on THI's free choice of sub-vendors within the attached "Approved Suppliers of Fabricated Equipment" list, subject to constraints of the subject inquiry. THI will not deviate from the attached list without Customer's prior written approval.

9.13 Waiver

THI's failure to insist on performance of any of the terms and conditions herein, or to exercise any right or privilege, or THI's waiver of any breach hereunder, shall not act as a waiver of any term, condition, right or privilege contained herein.

9.14 Warranty

Limitations; THI's warranty specifically excludes damages or failures caused by factors outside of THI's span of control, such as the improper design by Others of adjoining systems, the improper operation of said heater, or the intentional misapplication of same. Field evaluations of the proposed system(s) shall be performed at design conditions (as documented by THI's data sheets) and in strict accordance with the test methodologies set forth in API Std. 560. Repair or replacement of any item(s) shall be to the point of Sale specified in the Contract.

9.15 THI's Obligations

THI's obligation to remedy defective workmanship or material shall be limited to repairing or replacing the defective part or parts. No allowance shall be granted for repairs, or alterations, made by the Purchaser without THI's prior written consent. The decision to repair or replace

9.16 Purchaser's Obligations

The Purchaser, at his option and cost, may conduct a performance test to determine if the performance guarantees are being met. The Purchaser shall provide sufficient advance notice to THI so that a representative of THI can witness the test. Additionally, THI, will be given access to all operating data laboratory analysis that would bear on the final determination of performance. All analysis of operating test data will be performed in accordance with generally accepted engineering practices and using published physical data and procedures, as per API RP 532.

9.17 THI's Rights

THI reserves the right to replace or modify equipment not meeting performance guarantees in order to remedy that deficiency.

9.18 Limitations

THI's warranty does not apply to parts requiring replacement because of normal wear and tear, corrosion or erosion, or improper storage prior to initial start-up. The warranties set out above do not apply to products, components, accessories, parts or attachments manufactured by others; said products, components, accessories, parts or attachments being subject to the actual manufacturer's warranty, if any, which THI will pass on to Purchaser. Unless otherwise stated herein, THI does not represent that the components manufactured by others are covered by any warranty whatsoever. THI makes no warranty or representation that its products will conform to any federal, state or local laws, statutes, ordinances, regulations, codes or standards of any type or purpose, unless specifically incorporated in the contract between Purchaser and THI.

This warranty is IN LIEU of all other warranties, express or implied, arising by law or otherwise, including WARRANTY OF MERCHANTABILITY AND WARRANTY OF FITNESS FOR PARTICULAR PURPOSE, in lieu of all other liabilities of THI, including direct, indirect, special and consequential damages or penalties, expressed or implied.

10. APPENDICES

10.1 THI's ISO 9001 Certificate

10.2 Proposed FabShops

10.3 OEM Proposal - - Burners

10.4 OEM Proposal - - SCR System

10.5 OEM Proposal - - ID Fan

10.6 OEM Proposal - - BMS System

10.7 S&B C1498-M0013 Enclosure 1

10.8 THI's Major Projects
- Visit www.tulsaheaters.com for more information on THI's history and capability

Certificate

Partner for progress

Number	1101012
Valid from	18. March 2011
Valid until	17. March 2014

Kiwa International Cert GmbH
certifies that

Tulsa Heaters, Inc.

1350 S. Boulder, International Plaza #800
Tulsa, OK 74119 USA

for the scope

The design and sales of process fired heaters and waste heat recovery units to the petro-chemical industry

has implemented and applies a Quality Management System, which is in compliance with the requirements of

ISO 9001:2008

Kiwa International Cert GmbH
Managing Director

Kiwa International Cert GmbH
Technical Manager

Kiwa International Cert GmbH
Schloßmühlendamm 30
21073 Hamburg
Germany
Telefon +49 (0)40 30 39 49 60
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e-mail: info@kiwa.de
www.kiwa.de

Deutsche Gesellschaft für Akkreditierung mbH
DGA-ZM-05-09-00

ZERTIFIZIERT · REGISTERED · CERTIFICADO · CERTIFIE

INTERNATIONAL CERT

QMS APPROVED FABRICATORS ... DOMESTIC / U.S.A.

Ftnt & Rev.

Fabricators ... in alphabetical order	Casing & Structure	Int. & Ext. Coatings	Refractory	Coil	Ladders & Platforms	Comments
	<< --- ------ Approved Scope of Supply			------ --- >>		
Budgget Industries, Inc. Owasso, OK 74055	√	√			√	
Buckaloo Industrial Services Sand Springs, OK 74063		√	√			
By-Weld Industries, Inc. Bixby, OK 74008	√				√	
C-CAM Sand Springs, OK 74063	√	√	√	√		
Charger Blast & Paint Sand Springs, OK 74063		√				
Direct Fired LLC Sand Springs, OK 74063	√			√		
Econo-Fab Beggs, OK 74421				√		
Economaster Sand Springs, OK 74063				√		
General Steel Fabrication Joplin, MO 64801	√	√				External coatings only
Glass Design Sapulpa, OK 74067		√	√			Internal coatings only
Heater Specialists Inc. Tulsa, OK 74115	√	√	√	√		
JER-CO Industries, Inc. Locust Grove, OK 74352	√	√	√	√	√	
PARFAB Industries Inc. Claremore, OK 74017	√	√	√	√	√	
PRO-FAB Industries, Inc. Mannford, OK 74044	√			√		
Precision Fabricators Sand Springs, OK 74063	√			√		
R&S Steel Fabricating Co. Houston, TX	√	√	√	√	√	
R3 Industries Locust Grove, OK 74352	√					
Supreme Machine Co. Yale, OK 74085	√				√	

revision	date	description	by	chk'd	app'd
Rev. 08	5-Jul-07	Updated to reflect recent approvals	TLC	DON	PAT
Rev. 07	15-Feb-07	Updated to reflect recent approvals	TLC	DON	PAT
Rev. 06	7-Sep-06	Updated to reflect recent approvals	TLC	EVP	TBC

Job Specific Notes:
1) changes per QAM Section 7400
2) none
3) none

THI TULSA HEATERS INC.

TABLE 10.1: APPROVED FABRICATORS
QMS APPROVED SUPPLIERS

THIStandard -FAB1ds-08 **Page 1 of 1**

www.tulsaheaters.com ◆ info@tulsaheaters.com ◆ rfq@tulsaheaters.com ◆ TULSA HEATERS INC ◆ 1350 S. Boulder Ste 800 ◆ Tulsa, OK 74119 ◆ (918) 582-9918 ◆ (918) 582-9916 Fax

JZ Quotation: BU-201302-33706-A Rev. 0
THI Reference: P13-8431 A/B
Lone Star
03/05/2013 – Bailey Hendrix

Dear Mr. Burris,

Thank you for your interest in John Zink Company. We are pleased to submit this budget technical and commercial proposal which contains information that is considered confidential and proprietary to John Zink. The objective of this proposal is to present Tulsa Heaters with combustion solutions for your upcoming heater projects. John Zink reserves the right to hold a full technical and commercial meeting prior to any agreement to place and/or accept any purchase orders or LOI's.

Scope of Supply: COOLstar ARIA Burner Description

Based on the design requirements of this application we are pleased to offer our COOLstar ARIA style, staged gas burners. These burners have proven field performance in similar applications and with emissions levels as required by this project. Each burner will be complete with the following equipment in accordance with your request for quotation:

- High temperature, ceramic refractory burner tile with a maximum service temperature of 3000°F.
- CK-20 (310 equivalent) stainless steel fuel gas tips, 304 stainless steel tubing, zinc plated carbon steel tubing connectors and carbon steel manifold with a 150# 2" RFSW flanged gas connection.
- Integral, 10 ga carbon steel individual air plenum.
- Manual operation, radial inlet combustion air register assembly with a 10 ga carbon steel damper disk, locking multi-position adjustment and flow control position indicator plate.
- One (1) 2" swing away lighting port.
- One (1) 2" swing away sighting port.
- One (1) 1" NPT Swivel flame scanner mount sighted on the main flame.
- John Zink model ST-1SE-FR electrically ignited pilot complete with JZ standard flame rod. Gas connection to be 150# 1/2" RFSW flanged.
- Exterior carbon steel surfaces of the burner assembly will receive a surface preparation in accordance with SSPC-SP6, one coat of inorganic zinc, one coat of amine epoxy and one coat of polyurethane.
- 10% PMI of fuel wetted components by heat.
- MTR's for components with PMI.

BURNER DATA SHEET

300-HR-001 COOLstar-ARIA-16

CUSTOMER	Tulsa Heaters Inc.	HEATER ID NO.	300-HR-001		
END USER	Lone Star NGL	PURCHASE ORDER #	TBA		
LOCATION	Mont Belvieu, TX	BURNER REF. DWG.	TBA		
JZ QUOTE NO.	BU-201302-33706-A	JZ SALES ORDER NO.	TBA		
DOCUMENT NO.:	TBA	REVISION:	P	DATE:	03/04/13
APPLICATION ENGINEER	Bailey Hendrix	DESIGN ENGINEER	Kirk Wendel		
PROJECT MANAGER	TBA	TEST ENGINEER	TBA		

REVISION RECORD

No.	Revision Description	Date	By
P	Proposal	04-Mar-13	KW
0			
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			

JOHN ZINK HAMWORTHY COMBUSTION	BURNER DATA SHEET	SALES ORDER: TBA	Quote #: BU-201302-33706-A
		REVISION: P / DATE: 4-Mar-13	SHEET 1 of 3

CUSTOMER: Tulsa Heaters Inc. **Purchase Order #:** TBA

END USER: Lone Star NGL **LOCATION:** Mont Belvieu, TX

	HEATER GENERAL DATA			REV
1	HEATER EQUIPMENT NUMBER		300-HR-001	
2	HEATER SERVICE		Hot Oil Heater	
3	HEATER MANUFACTURER		THI	
4	TYPE OF HEATER	VC [Vertical Cylindrical] or BOX or CABIN	VC	
5	SETTING REFRACTORY THICKNESS	inches	12.5	
6	HEATER CASING THICKNESS	inches	0.25	
7	FIREBOX INTERIOR HEIGHT from FLOOR TO ARCH	feet	62.45	
8	FIREBOX CELL INTERIOR LENGTH from WALL TO WALL	feet	--	
9	FIREBOX CELL INTERIOR WIDTH	feet	--	
10	TUBE CIRCLE DIAMETER [VERTICAL CYLINDRICAL HEATER]	feet	29.28	
11	COMBUSTION AIR PLENUM	COMMON or INDIVIDUAL	Individual	
	BURNER DATA			
12	TYPE OF BURNER	LOW NOx or ULTRA-LOW Nox	Ultra Low NOx	
13	BURNER PROJECT CLASSIFICATION	NEW or REPLACE or RETROFIT	New	
14	BURNER MODEL		COOLstar-ARIA	
15	BURNER SIZE		16	
16	QUANTITY of BURNERS REQUIRED PER CELL		12	
17	QUANTITY of CELLS REQUIRED PER FURNACE		1	
18	QUANTITY of FURNACES		1	
19	TOTAL QUANTITY OF BURNERS		12	
20	FIRING ORIENTATION	UPFIRED or DOWNFIRED or HORIZONTAL	Up-fired	
21	BURNER INSTALLED LOCATION	ROOF or FLOOR or WALL	Floor	
22	BURNER CENTERLINE TO TUBE CENTERLINE	inches	68.46	
23	BURNER CENTERLINE TO ADJACENT BURNER CENTERLINE	inches	55.5	
24	BURNER CENTERLINE TO UNSHIELDED REFRACTORY	inches	--	
25	BURNER CIRCLE DIAMETER [VERTICAL CYLINDRICAL HEATER]	feet	17.87	
26	PILOT REQUIRED?	YES or NO	Yes	
27	PILOT MODEL		ST-1-SE-FR	
28	PILOT IGNITION METHOD	MANUAL or ELECTRIC	Electric	
29	FLAME ROD	YES or NO	Yes	
30	PILOT FUEL		Design RFG	
31	FUEL PRESSURE at PILOT	psig	10	
32	PILOT HEAT RELEASE	Btu/hr	75,000	
33	PILOT CONNECTION	1/2" FNPT or 1/2" R.F.	1/2", 150# RFSW	
34	PILOT IGNITION TRANSFORMER VOLTAGE	120VAC or 220VAC	by others	
35	PILOT IGNITION TRANSFORMER HOUSING	NEMA 4 or NEMA 7	by others	
	OPERATING DATA			
36	BURNER FUEL TYPE	GAS or OIL or GAS & OIL	Gas	
37	HEATER DRAFT TYPE(S)	FORCED or NATURAL or INDUCED	Induced	
38	HEATER MAXIMUM HEAT RELEASE	MMBtu/hr (LHV)	191	
39	MAXIMUM HEAT RELEASE per BURNER	MMBtu/hr (LHV)	15.91	
40	DESIGN HEAT RELEASE per BURNER	MMBtu/hr (LHV)	15.91	
41	NORMAL HEAT RELEASE per BURNER	MMBtu/hr (LHV)	14.47	
42	MINIMUM HEAT RELEASE per BURNER	MMBtu/hr (LHV)	3.18	
43	BURNER TURNDOWN REQUIRED		5 : 1	
44	EXCESS AIR at DESIGN HEAT RELEASE	%	15.0%	
45	COMBUSTION AIR SOURCE	AMBIENT or PREHEAT	Ambient	
46	MAXIMUM COMBUSTION AIR TEMPERATURE at BURNER	°F	105	
47	**DESIGN** COMBUSTION AIR TEMPERATURE at BURNER	°F	105	
48	MINIMUM COMBUSTION AIR TEMPERATURE at BURNER	°F	10	
49	MAXIMUM AVAILABLE DRAFT at BURNER	inH_2O	1.00	
50	AVAILABLE BURNER AIR PRESSURE DROP at DESIGN HEAT RELEASE	inH_2O	0.95	
51	AVAILABLE BURNER AIR PRESSURE DROP at NORMAL HEAT RELEASE	inH_2O		
52	AVAILABLE BURNER AIR PRESSURE DROP at MINIMUM HEAT RELEASE	inH_2O		
53	AMBIENT AIR TEMPERATURE	°F	60	
54	AMBIENT AIR RELATIVE HUMIDITY	%	50%	
55	HEATER ELEVATION ABOVE SEA LEVEL	feet	69	
56	ESTIMATED VISIBLE FLAME LENGTH at DESIGN HEAT RELEASE	feet	28	
57	ESTIMATED VISIBLE FLAME DIAMETER at DESIGN HEAT RELEASE	feet	4	

JOHN ZINK HAMWORTHY COMBUSTION	BURNER DATA SHEET	SALES ORDER		Quote #
		TBA		BU-201302-33706-A
		REVISION:	DATE:	**SHEET**
		P	04-Mar-13	**2 of 3**

GAS FUEL CHARACTERISTICS

									REV
58	EMISSION GUARANTEES APPLICABLE			Yes	Yes				
59	FUEL GAS DESIGNATION			Design	C2				
60	HEATING VALUE	* [LHV]	Btu/scf	942	1,619				
61	HEATING VALUE	* [HHV]	Btu/scf	1,045	1,770				
62	SPECIFIC GRAVITY [AIR = 1.0]			0.59	1.04				
63	MOLECULAR WEIGHT			17.02	30.08				
64	ISENTROPIC COEFFICIENT			1.29	1.18				
65	FUEL TEMPERATURE at BURNER		°F	100	100				
66	FUEL PRESSURE AVAILABLE at BURNER		psig	30	30				
67	MAXIMUM HEAT RELEASE AVAILABLE PER BURNER	MMBtu/hr	(LHV)						
68	FUEL GAS COMPOSITION		Volume%						
69	Methane	(CH_4)		93.04					
70	Ethane	(C_2H_6)		5.77	100.00				
71	Propane	(C_3H_8)		0.11					
72	Butane	(C_4H_{10})							
73	Pentane	(C_5H_{12})							
74	Hexane plus	(C_6 +)							
75	Cyclopentane	(C_5H_{10})							
76	Cyclohexane	(C_6H_{12})							
77	Ethylene	(C_2H_4)							
78	Propene	(C_3H_6)							
79	Butene	(C_4H_8)							
80	Pentene	(C_5H_{10})							
81	Butadiene	(C_4H_6)							
82	Carbon Dioxide	(CO_2)							
83	Water	(H_2O)							
84	Oxygen	(O_2)							
85	Nitrogen	(N_2)		1.08					
86	Sulfur Dioxide	(SO_2)							
87	Hydrogen Sulfide	(H_2S)							
88	Carbon Monoxide	(CO)							
89	Ammonia	(NH_3)							
90	Hydrogen	(H_2)							
91	Argon	(Ar)							
92	Acetylene	(C_2H_2)							
93	Benzene	(C_6H_6)							
94			TOTAL	100.0	100.0				

LIQUID FUEL CHARACTERISTICS

95	FUEL OIL DESIGNATION								
96	HEATING VALUE	* [LHV]	Btu/lb						
97	SPECIFIC GRAVITY								
98	HYDROGEN to CARBON RATIO [BY WEIGHT]								
99	VISCOSITY [POINT 1] at	°F	SSU						
100	VISCOSITY [POINT 2] at	°F	SSU						
101	DISTILLATION : ASTM INITIAL BOILING POINT		°F						
102	ASTM MID-POINT		°F						
103	ASTM END POINT		°F						
104	FUEL TEMPERATURE at BURNER		°F						
105	FUEL PRESSURE AVAILABLE at BURNER		psig						
106	ATOMIZING MEDIUM		*AIR or STEAM or MECHANICAL or GAS*						
107	ATOMIZING MEDIUM TEMPERATURE at BURNER		°F						
108	ATOMIZING MEDIUM PRESSURE at BURNER		psig						
109	FUEL OIL METALS: Vanadium, Potassium, Sodium, Nickel		wppm						
110	FUEL OIL COMPOSITION		Weight%						
111	Carbon	(C)							
112	Hydrogen	(H)							
113	Oxygen	(O)							
114	Fixed Nitrogen	(N)							
115	Sulfur	(S)							
116	Ash								
117	Water	(H_2O)							
118			TOTAL						

JOHN ZINK HAMWORTHY COMBUSTION	BURNER DATA SHEET	SALES ORDER	Quote #
		TBA	BU-201302-33706-A
		REVISION: P	DATE: 4-Mar-13
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EMISSION REQUIREMENTS

				REV
119	HEATER EQUIPMENT NUMBER		**300-HR-001**	
120	BURNER MODEL NUMBER		**COOLstar-ARIA-16**	
121	FIREBOX TEMPERATURE DETERMINATION	*MEASURED, ESTIMATED, or CALCULATED*	Estimated	
122	FIREBOX BRIDGEWALL TEMPERATURE at DESIGN HEAT RELEASE	°F	1582	
123	NOx GUARANTEE at DESIGN EXCESS AIR DOWN TO	MMBtu/hr (LHV)	14.47	
124	FIREBOX BRIDGEWALL TEMPERATURE at 91% OF DESIGN HEAT RELEASE	°F	1582	
125	FIREBOX TEMPERATURE AT BURNER LOCATION	°F	1390	
126	CO, VOC, UHC, & PM10 GUARANTEES DOWN TO FIREBOX TEMPERATURE OF	°F	1500	
127	NOx (guaranteed)	lb/MMBtu (LHV)	0.038	
128	CO (guaranteed)	lb/MMBtu (LHV)	0.03	
129	VOC (guaranteed)	lb/MMBtu (LHV)	0.03	
130	UHC (guaranteed)	lb/MMBtu (LHV)	0.03	
131	PM10 (guaranteed)	lb/MMBtu (LHV)	0.008	
132				
133	***EMISSIONS VALID WHEN OPERATING DESIGN EXCESS AIR**			
134	***CORRECTED TO 3% O_2 [DRY BASIS at DESIGN HEAT RELEASE]**			
135	SINGLE BURNER NOISE THRESHOLD SPECIFICATION	dBA at 3 ft or 1 m	85	

SPECIFICATION OPTIONS

136	PRESSURE TAP REQUIRED	*YES or NO*	No	
137	SPECIAL GAUGES	*Specify*	No	
138	SPECIAL VALVES	*Specify*	No	
139	SPECIAL HOSES	*Specify*	No	
140	FLANGED FUEL CONNECTIONS	*YES or NO*	Yes 150# RFSW	
141	ENGINEERING UNITS on DRAWINGS	*ENGLISH or METRIC or S.I.*	English	
142	POSITIVE MATERIAL IDENTIFICATION [PMI] REQUIRED	*YES or NO*	No	
143	MILL CERTIFICATIONS REQUIRED	*YES or NO*	No	
144	BURNER PERFORMANCE TEST REQUIRED	*YES or NO*	Optional	
145				

NOTES AND COMMENTS

146	1) VOC emissions are non-Methane, non-Ethane, reported as Methane.	
147	2) UHC are reported as Methane.	
148	3) PM10 guarantees are based on those components of solid matter directly generated through incomplete combustion and are exclusive of solid products of complete	
149	combustion, refractory particulate, residual ash, and air-borne matter.	
150		
151		
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156		
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158		

TIP DRILLING INFORMATION

159	**GAS TIP DRILLINGS:**					
160	**PRIMARY GAS TIPS:**					
161	PRIMARY IGNITION PORTS:		~			
162	PRIMARY CROSSOVER PORTS:		~			
163	PRIMARY FIRING PORTS:		~			
164	PRIMARY SPUD:		~			
165	**STAGED GAS TIPS:**					
166	STAGED IGNITION PORTS:		~			
167	STAGED CROSSOVER PORTS:		~			
168	STAGED FIRING PORTS:		~			
169						
170	**PILOT INFORMATION**					
171	PILOT ORIFICE DRILLED:	(1)	~	1/16	inch	
172	PILOT PRESSURE REQUIRED	7-15 PSIG				

BURNER DATA SHEET

300-HR-002 COOLstar-ARIA-16

CUSTOMER	Tulsa Heaters Inc.	HEATER ID NO.	300-HR-002		
END USER	Lone Star NGL	PURCHASE ORDER #	TBA		
LOCATION	Mont Belvieu, TX	BURNER REF. DWG.	TBA		
JZ QUOTE NO.	BU-201302-33706-A	JZ SALES ORDER NO.	TBA		
DOCUMENT NO.:	TBA	REVISION:	P	DATE:	03/04/13
APPLICATION ENGINEER	Bailey Hendrix	DESIGN ENGINEER	Kirk Wendel		
PROJECT MANAGER	TBA	TEST ENGINEER	TBA		

REVISION RECORD

No.	Revision Description	Date	By
P	Proposal	04-Mar-13	KW
0			
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			

JOHN ZINK HAMWORTHY COMBUSTION

BURNER DATA SHEET

SALES ORDER	Quote #
TBA	BU-201302-33706-A

REVISION:	DATE:	SHEET
P	4-Mar-13	1 of 3

CUSTOMER: Tulsa Heaters Inc. **Purchase Order #:** TBA

END USER: Lone Star NGL **LOCATION:** Mont Belvieu, TX

HEATER GENERAL DATA

				REV
1	HEATER EQUIPMENT NUMBER		300-HR-002	
2	HEATER SERVICE		Regen Gas Heater	
3	HEATER MANUFACTURER		THI	
4	TYPE OF HEATER	*VC [Vertical Cylindrical] or BOX or CABIN*	VC	
5	SETTING REFRACTORY THICKNESS	inches	11.5	
6	HEATER CASING THICKNESS	inches	0.25	
7	FIREBOX INTERIOR HEIGHT from FLOOR TO ARCH	feet	40.30	
8	FIREBOX CELL INTERIOR LENGTH from WALL TO WALL	feet	--	
9	FIREBOX CELL INTERIOR WIDTH	feet	--	
10	TUBE CIRCLE DIAMETER [VERTICAL CYLINDRICAL HEATER]	feet	15.01	
11	COMBUSTION AIR PLENUM	*COMMON or INDIVIDUAL*	Individual	

BURNER DATA

12	TYPE OF BURNER	*LOW NOx or ULTRA-LOW Nox*	Ultra Low NOx	
13	BURNER PROJECT CLASSIFICATION	*NEW or REPLACE or RETROFIT*	New	
14	BURNER MODEL		**COOLstar-ARIA**	
15	BURNER SIZE		16	
16	QUANTITY of BURNERS REQUIRED PER CELL		4	
17	QUANTITY of CELLS REQUIRED PER FURNACE		1	
18	QUANTITY of FURNACES		1	
19	TOTAL QUANTITY OF BURNERS		4	
20	FIRING ORIENTATION	*UPFIRED or DOWNFIRED or HORIZONTAL*	Up-fired	
21	BURNER INSTALLED LOCATION	*ROOF or FLOOR or WALL*	Floor	
22	BURNER CENTERLINE TO TUBE CENTERLINE	inches		
23	BURNER CENTERLINE TO ADJACENT BURNER CENTERLINE	inches		
24	BURNER CENTERLINE TO UNSHIELDED REFRACTORY	inches	--	
25	BURNER CIRCLE DIAMETER [VERTICAL CYLINDRICAL HEATER]	feet	6.19	
26	PILOT REQUIRED?	*YES or NO*	Yes	
27	PILOT MODEL		ST-1-SE-FR	
28	PILOT IGNITION METHOD	*MANUAL or ELECTRIC*	Electric	
29	FLAME ROD	*YES or NO*	Yes	
30	PILOT FUEL		Design RFG	
31	FUEL PRESSURE at PILOT	psig	10	
32	PILOT HEAT RELEASE	Btu/hr	75,000	
33	PILOT CONNECTION	*1/2" FNPT or 1/2" R.F.*	1/2", 150# RFSW	
34	PILOT IGNITION TRANSFORMER VOLTAGE	*120VAC or 220VAC*	by others	
35	PILOT IGNITION TRANSFORMER HOUSING	*NEMA 4 or NEMA 7*	by others	

OPERATING DATA

36	BURNER FUEL TYPE	*GAS or OIL or GAS & OIL*	Gas	
37	HEATER DRAFT TYPE(S)	*FORCED or NATURAL or INDUCED*	Induced	
38	HEATER MAXIMUM HEAT RELEASE	MMBtu/hr (LHV)	53	
39	MAXIMUM HEAT RELEASE per BURNER	MMBtu/hr (LHV)	13.22	
40	DESIGN HEAT RELEASE per BURNER	MMBtu/hr (LHV)	13.22	
41	NORMAL HEAT RELEASE per BURNER	MMBtu/hr (LHV)	11.50	
42	MINIMUM HEAT RELEASE per BURNER	MMBtu/hr (LHV)	2.64	
43	BURNER TURNDOWN REQUIRED		5 : 1	
44	EXCESS AIR at DESIGN HEAT RELEASE	%	15.0%	
45	COMBUSTION AIR SOURCE	*AMBIENT or PREHEAT*	Ambient	
46	MAXIMUM COMBUSTION AIR TEMPERATURE at BURNER	°F	105	
47	**DESIGN** COMBUSTION AIR TEMPERATURE at BURNER	°F	105	
48	MINIMUM COMBUSTION AIR TEMPERATURE at BURNER	°F	10	
49	MAXIMUM AVAILABLE DRAFT at BURNER	inH_2O	0.71	
50	AVAILABLE BURNER AIR PRESSURE DROP at DESIGN HEAT RELEASE	inH_2O	0.67	
51	AVAILABLE BURNER AIR PRESSURE DROP at NORMAL HEAT RELEASE	inH_2O		
52	AVAILABLE BURNER AIR PRESSURE DROP at MINIMUM HEAT RELEASE	inH_2O		
53	AMBIENT AIR TEMPERATURE	°F	60	
54	AMBIENT AIR RELATIVE HUMIDITY	%	50%	
55	HEATER ELEVATION ABOVE SEA LEVEL	feet	69	
56	ESTIMATED VISIBLE FLAME LENGTH at DESIGN HEAT RELEASE	feet	24	
57	ESTIMATED VISIBLE FLAME DIAMETER at DESIGN HEAT RELEASE	feet	4	

JOHN ZINK HAMWORTHY COMBUSTION	BURNER DATA SHEET	SALES ORDER: TBA	Quote #: BU-201302-33706-A
		REVISION: P / DATE: 04-Mar-13	SHEET 2 of 3

GAS FUEL CHARACTERISTICS

									REV
58	EMISSION GUARANTEES APPLICABLE			Yes	Yes				
59	FUEL GAS DESIGNATION			Design	C2				
60	HEATING VALUE	* [LHV]	Btu/scf	942	1,619				
61	HEATING VALUE	* [HHV]	Btu/scf	1,045	1,770				
62	SPECIFIC GRAVITY [AIR = 1.0]			0.59	1.04				
63	MOLECULAR WEIGHT			17.02	30.08				
64	ISENTROPIC COEFFICIENT			1.29	1.18				
65	FUEL TEMPERATURE at BURNER		°F	100	100				
66	FUEL PRESSURE AVAILABLE at BURNER		psig	30	30				
67	MAXIMUM HEAT RELEASE AVAILABLE PER BURNER	MMBtu/hr	(LHV)						
68	FUEL GAS COMPOSITION		Volume%						
69	Methane	(CH_4)		93.04					
70	Ethane	(C_2H_6)		5.77	100.00				
71	Propane	(C_3H_8)		0.11					
72	Butane	(C_4H_{10})							
73	Pentane	(C_5H_{12})							
74	Hexane plus	(C_6 +)							
75	Cyclopentane	(C_5H_{10})							
76	Cyclohexane	(C_6H_{12})							
77	Ethylene	(C_2H_4)							
78	Propene	(C_3H_6)							
79	Butene	(C_4H_8)							
80	Pentene	(C_5H_{10})							
81	Butadiene	(C_4H_6)							
82	Carbon Dioxide	(CO_2)							
83	Water	(H_2O)							
84	Oxygen	(O_2)							
85	Nitrogen	(N_2)		1.08					
86	Sulfur Dioxide	(SO_2)							
87	Hydrogen Sulfide	(H_2S)							
88	Carbon Monoxide	(CO)							
89	Ammonia	(NH_3)							
90	Hydrogen	(H_2)							
91	Argon	(Ar)							
92	Acetylene	(C_2H_2)							
93	Benzene	(C_6H_6)							
94			TOTAL	100.0	100.0				

LIQUID FUEL CHARACTERISTICS

95	FUEL OIL DESIGNATION								
96	HEATING VALUE	* [LHV]	Btu/lb						
97	SPECIFIC GRAVITY								
98	HYDROGEN to CARBON RATIO [BY WEIGHT]								
99	VISCOSITY [POINT 1] at	°F	SSU						
100	VISCOSITY [POINT 2] at	°F	SSU						
101	DISTILLATION : ASTM INITIAL BOILING POINT		°F						
102	ASTM MID-POINT		°F						
103	ASTM END POINT		°F						
104	FUEL TEMPERATURE at BURNER		°F						
105	FUEL PRESSURE AVAILABLE at BURNER		psig						
106	ATOMIZING MEDIUM		*AIR or STEAM or MECHANICAL or GAS*						
107	ATOMIZING MEDIUM TEMPERATURE at BURNER		°F						
108	ATOMIZING MEDIUM PRESSURE at BURNER		psig						
109	FUEL OIL METALS: Vanadium, Potassium, Sodium, Nickel		wppm						
110	FUEL OIL COMPOSITION		Weight%						
111	Carbon	(C)							
112	Hydrogen	(H)							
113	Oxygen	(O)							
114	Fixed Nitrogen	(N)							
115	Sulfur	(S)							
116	Ash								
117	Water	(H_2O)							
118			TOTAL						

JOHN ZINK HAMWORTHY COMBUSTION	BURNER DATA SHEET	SALES ORDER	Quote #
		TBA	BU-201302-33706-A
		REVISION: P / DATE: 4-Mar-13	SHEET 3 of 3

EMISSION REQUIREMENTS

				REV
119	HEATER EQUIPMENT NUMBER		**300-HR-002**	
120	BURNER MODEL NUMBER		**COOLstar-ARIA-16**	
121	FIREBOX TEMPERATURE DETERMINATION	*MEASURED, ESTIMATED, or CALCULATED*	Estimated	
122	FIREBOX BRIDGEWALL TEMPERATURE at DESIGN HEAT RELEASE	°F	1442	
123	NOx GUARANTEE at DESIGN EXCESS AIR DOWN TO	MMBtu/hr (LHV)	11.50	
124	FIREBOX BRIDGEWALL TEMPERATURE at 87% OF DESIGN HEAT RELEASE	°F	1442	
125	FIREBOX TEMPERATURE AT BURNER LOCATION	°F	1250	
126	CO, VOC, UHC, & PM10 GUARANTEES DOWN TO FIREBOX TEMPERATURE OF	°F	1400	
127	NOx (guaranteed)	lb/MMBtu (LHV)	0.038	
128	CO (guaranteed)	lb/MMBtu (LHV)	0.03	
129	VOC (guaranteed)	lb/MMBtu (LHV)	0.03	
130	UHC (guaranteed)	lb/MMBtu (LHV)	0.03	
131	PM10 (guaranteed)	lb/MMBtu (LHV)	0.025	
132				
133	***EMISSIONS VALID WHEN OPERATING DESIGN EXCESS AIR**			
134	***CORRECTED TO 3% O_2 [DRY BASIS at DESIGN HEAT RELEASE]**			
135	SINGLE BURNER NOISE THRESHOLD SPECIFICATION	dBA at 3 ft or 1 m	85	

SPECIFICATION OPTIONS

136	PRESSURE TAP REQUIRED	*YES or NO*	No	
137	SPECIAL GAUGES	*Specify*	No	
138	SPECIAL VALVES	*Specify*	No	
139	SPECIAL HOSES	*Specify*	No	
140	FLANGED FUEL CONNECTIONS	*YES or NO*	Yes 150# RFSW	
141	ENGINEERING UNITS on DRAWINGS	*ENGLISH or METRIC or S.I.*	English	
142	POSITIVE MATERIAL IDENTIFICATION [PMI] REQUIRED	*YES or NO*	No	
143	MILL CERTIFICATIONS REQUIRED	*YES or NO*	No	
144	BURNER PERFORMANCE TEST REQUIRED	*YES or NO*	Optional	
145				

NOTES AND COMMENTS

146 1) VOC emissions are non-Methane, non-Ethane, reported as Methane.
147 2) UHC are reported as Methane.
148 3) PM10 guarantees are based on those components of solid matter directly generated through incomplete combustion and are exclusive of solid products of complete
149 combustion, refractory particulate, residual ash, and air-borne matter.
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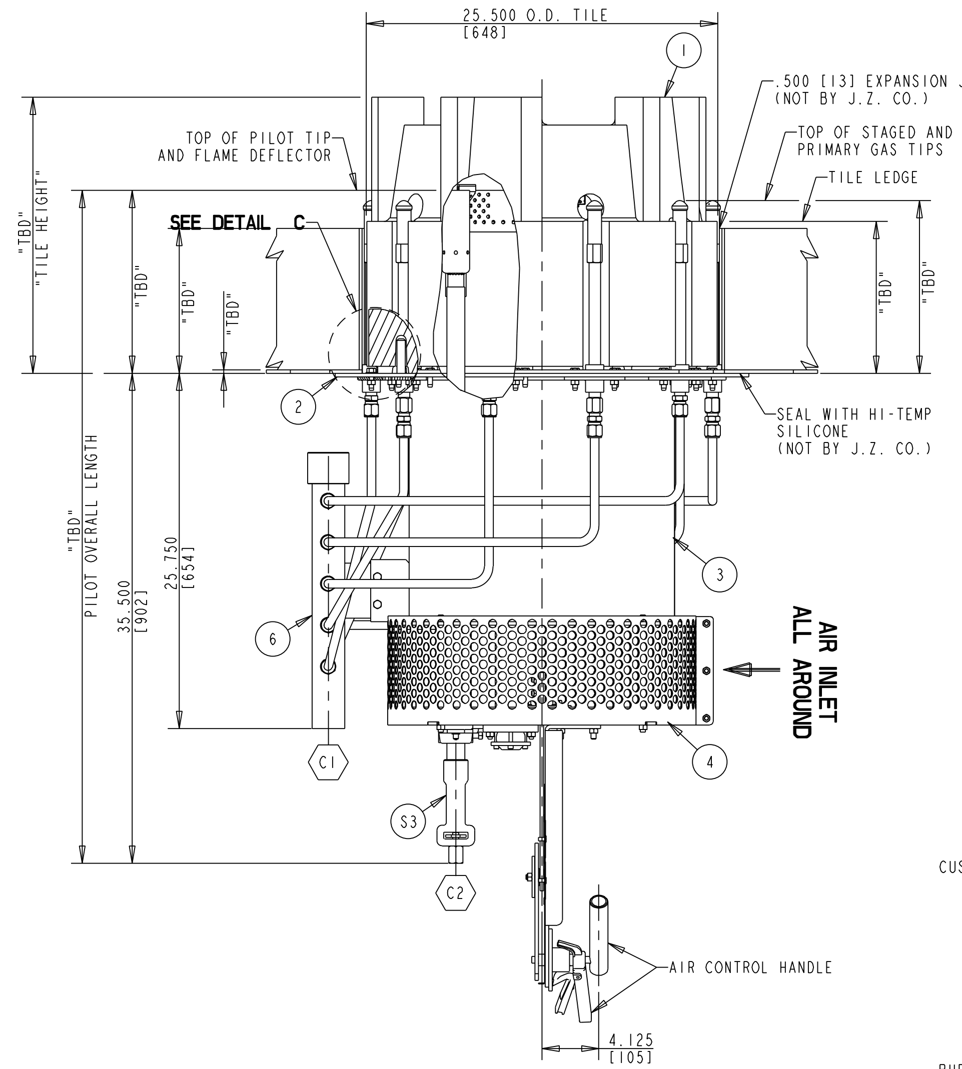
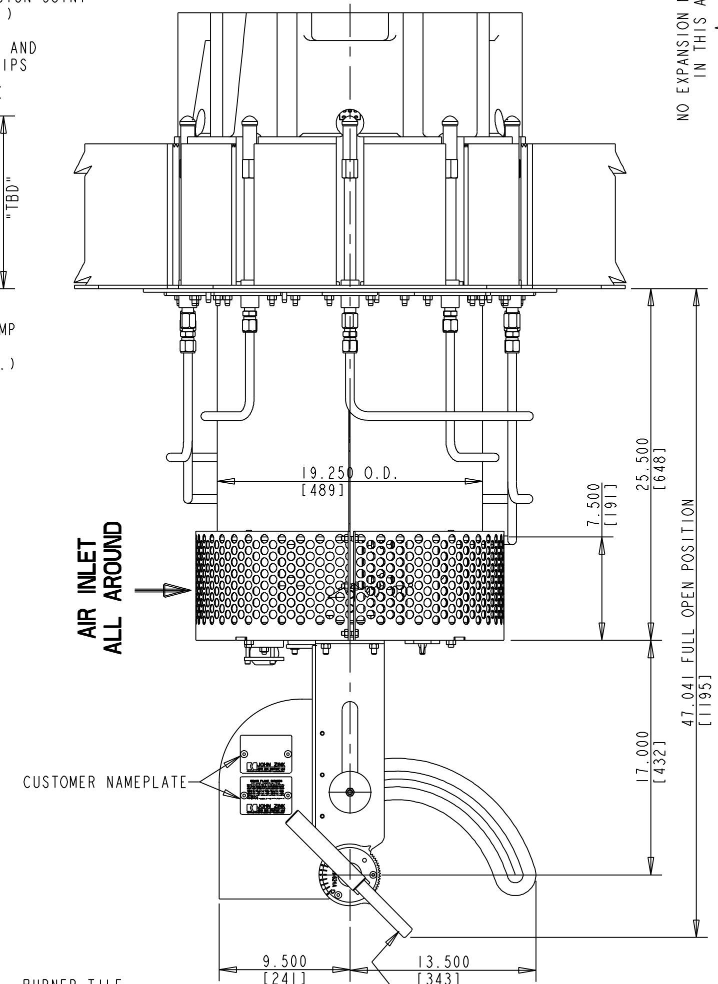
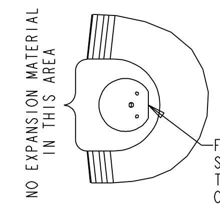
TIP DRILLING INFORMATION

159	**GAS TIP DRILLINGS:**				
160	**PRIMARY GAS TIPS:**				
161	PRIMARY IGNITION PORTS:		~		
162	PRIMARY CROSSOVER PORTS:		~		
163	PRIMARY FIRING PORTS:		~		
164	PRIMARY SPUD:		~		
165	**STAGED GAS TIPS:**				
166	STAGED IGNITION PORTS:		~		
167	STAGED CROSSOVER PORTS:		~		
168	STAGED FIRING PORTS:		~		
169					
170	**PILOT INFORMATION**				
171	PILOT ORIFICE DRILLED:	(1)	~	1/16	inch
172	PILOT PRESSURE REQUIRED	7-15 PSIG			

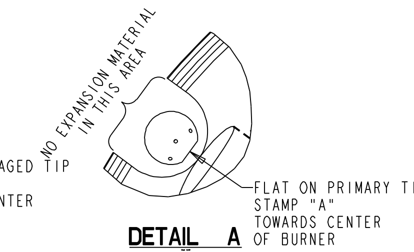


PART SECTION ELEVATION

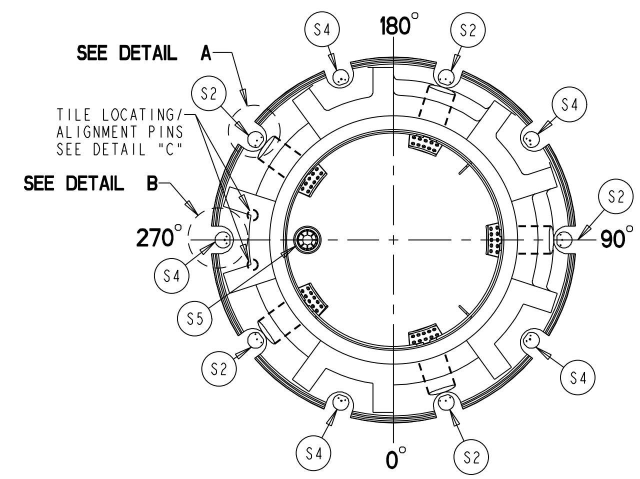




DETAIL B



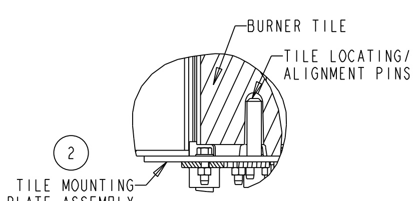
DETAIL A



TILE VIEW

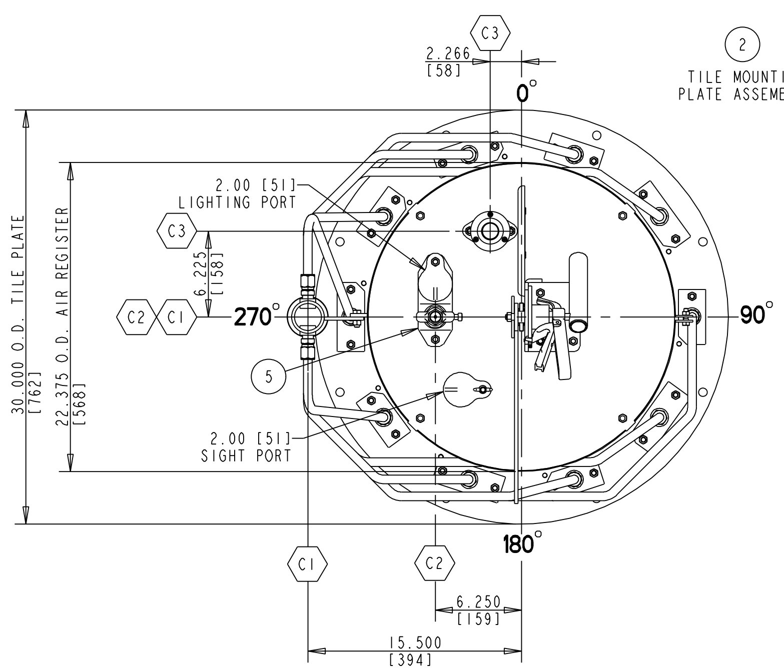
******CAUTION******

GAS TIPS, TILE INSTALLATION AND ORIENTATION ARE CRITICAL TO PROPER BURNER OPERATION AND SAFETY. REFER TO TILE VIEW FOR CORRECT GAS TIPS AND TILE ORIENTATION. REFER TO OPERATION, INSTALLATION AND MAINTENANCE MANUAL FOR ADDITIONAL DETAILS.

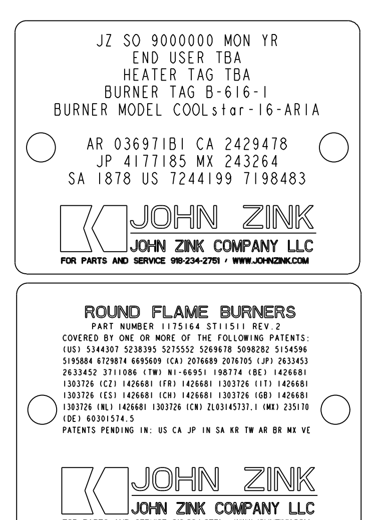


DETAIL C

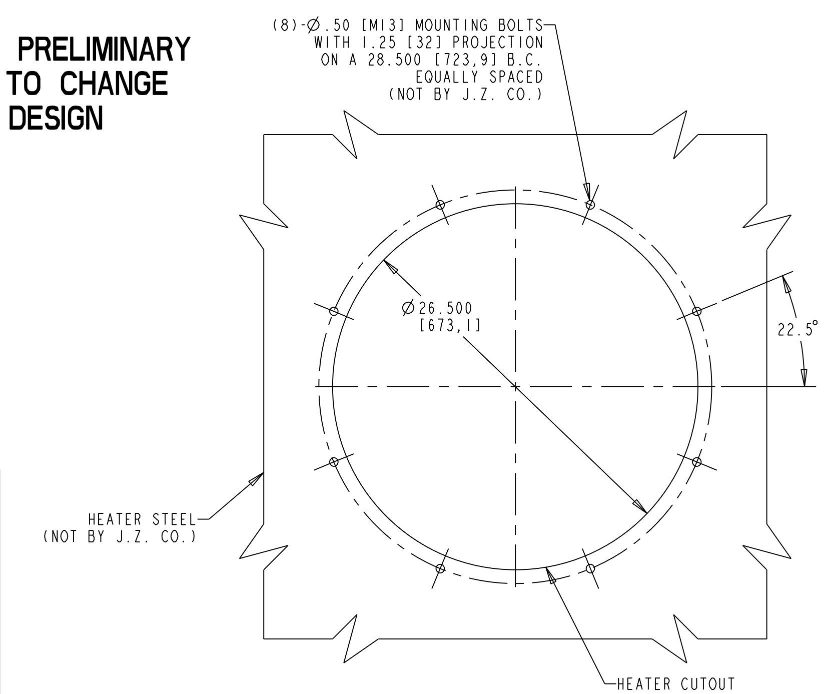
DIMENSIONS ARE PRELIMINARY AND SUBJECT TO CHANGE ON FINAL DESIGN



BOTTOM VIEW
(TRUE ORIENTATION)



CUSTOMER NAMEPLATE



MOUNTING DETAIL

PARTS LIST

ITEM	QTY	DESCRIPTION	DWG NO	MATERIAL	PART NO
1	1	BURNER TILE N.S.P.(ONE PIECE)	ST11102	SEE NOTE 2	.
2	1	TILE MOUNTING PLATE ASSEMBLY	B-71416	A-36	.
3	1	PLENUM ASSEMBLY	B-70316	C.S.	.
4	1	FRONT PLATE AND REGISTER ASS'Y	B-70616	C.S./S.S.	.
5	1	ST-1-S MANUAL PILOT ASS'Y	B-ST-3922	MFG STD	.
6	1	MANIFOLD AND RISERS ASSEMBLY	B-70816	CS/304SS/CK-20	.
S1	5	ORIFICE SPUD, INLINE	CA-PAT-1898	CF8	.
S2	5	PRIMARY RISER ASS'Y-TIP STAMP "A"	B-71116	CF8/304SS/CK-20	.
S3	1	PILOT MIXER ASS'Y	CA-ST-0619	C.S.	0019498
S4	5	STAGED RISER ASS'Y-TIP STAMP "B"	B-71016	CF8/304SS/CK-20	.
S5	1	ST-1-S TIP ASSY	CA-ST-0606	CK-20	0001448

NOZZLE LEGEND

C1	1	FUEL GAS CONNECTION: 2" MALE N.P.T.
C2	1	PILOT GAS CONNECTION: 1/2" FEMALE N.P.T.
C3	1	SWIVEL SCANNER CONNECTION: 1" FEMALE N.P.T.

NOTES

1. ALL EXTERNAL CARBON STEEL SURFACES TO BE CLEANED PER SSPC-SP2 AND PAINTED WITH ONE SHOPCOAT INORGANIC ZINC PRIMER.
2. BURNER TILE MATERIAL TO BE 3000°F [1650°C] SERVICE TEMPERATURE.
3. FOR ADDITIONAL ENGINEERING INFORMATION SEE JOHN ZINK DATA SHEET B-9000000-816 AND CAPACITY CURVE B-9000000-816-A.
4. SHIP LOOSE ITEMS TAG:
   BURNER ASSEMBLY B-616-1
   BURNER TILE ST11102-2
5. BURNER TILE SET WEIGHT = 387 lbs. [176 kg]
   BURNER ASSEMBLY WEIGHT = 253 lbs. [115 kg]
   TOTAL WEIGHT = 640 lbs. [290 kg]
6. DIMENSIONS SHOWN IN [ ] ARE MILLIMETERS.
7. NO PIPING LOAD ALLOWANCE ON MANIFOLD.
8. "S" NUMBERS ARE RECOMMENDED REPLACEMENT PARTS.
9. DO NOT PAINT STAINLESS STEEL COMPONENTS.
10. ALL FLANGE BOLTING TO STRADDLE NORMAL CENTERLINES.

MANUFACTURING AND INSTALLATION TOLERANCE LEGEND

FUEL PORT ANGLE: ±2°
MOUNTING DIMENSIONS: ±.125 [3]
PIPING CONNECTION DIMENSIONS: ±.50 [13]
OTHER DIMENSIONS WITH TOLERANCES AS SHOWN
ALL OTHER DIMENSIONS WITHOUT TOLERANCES ARE SHOWN AS REFERENCE ONLY

REVISION 4	
REVISION 3	
REVISION 2	
REVISION 1	

FOR: TBA	JOHN ZINK COMPANY, LLC PARTS AND SERVICE, CALL 1-800-755-4252 FAX (918) 234-1968			
USER: TBA				
JOBSITE: TBA				
	COOLstar-16-ARIA BURNER ASSEMBLY			
S.O. NO.:	FOR HEATER TBA			
P.O. NO.: TBA				
DR: TRAN	DATE:01-13	CERTIFIED	DRAWING NUMBER 9000000-616	REV. 0
CK: THT	DATE:01-13			
APP.: .	DATE:01-13	DATE: 01-13	SCALE NONE	

BASE NUMBER	PART NUMBER
B-616	.

PEERLESS

Making Energy Safe, Efficient and Clean.

TULSA HEATERS, INC.

ALLEN BURRIS

for

LONE STAR FRAC III PROJECT

PROJECT REFERENCE: P13-8431A
PEERLESS PROPOSAL REFERENCE NUMBER: 26998

MARCH 8, 2013

I. BUDGETARY PRICE SUMMARY: AQUEOUS ELECTRIC SCR SYSTEM

ITEM	QUANTITY	DESCRIPTION	PRICE
A	1	Ammonia Flow Control Unit (AFCU)	
B	1	Ammonia Injection Manifold	
C	1	Ammonia Injection Grid (AIG)	
D	1	Reactor Housing	
E	1	SCR Catalyst Support Structure and Seals	
F	1	SCR Catalyst	
G	1	Manual hoist and monorail	
1	**OPTION**	Freight is on a pre-pay and add basis, billed at cost (base bid scope of supply only)	
2	**OPTION**	**Adder** for Peerless standard PLC, Allen Bradley CompactLogix PLC	
3	**OPTION**	**Adder** for computation fluid dynamics modeling	
4	**OPTION**	Field Service / Supervision One trip / five days is recommended per unit.	

All Purchase Orders based on this Quote, which is not an offer, are subject to acceptance by Seller at its principal office in Dallas, Texas. Unless otherwise expressly provided in Seller's acceptance, the terms and conditions set forth herein shall constitute a part of any agreement resulting from Seller's acceptance of an order for all or part of the goods covered by this Quote. This Quote serves as notice to Buyer of Seller's objection to any terms and conditions of Buyer that in any way conflict with, modify, condition, add to, or differ from the terms and conditions specified herein, unless such terms and conditions of Buyer are expressly included in Seller's acceptance of Buyer's order. Silence on the part of Seller shall not be construed, under any circumstances, as acceptance of Buyer's terms and conditions. If not previously revoked or otherwise provided herein, this Quote shall terminate and cease to exist thirty (30) days from the date of this Quote.

Natalie Boone
nboone@peerlessmfg.com

CC: Joe Rios, Peerless Mfg. Co.

II. COMMERCIAL TERMS

A. **PROPOSAL PRICE:** The price proposed is for the design, materials, or components listed. If specific design conditions differ from the inquiry, the specifications shall be modified and an equitable adjustment shall be made in the contract price or delivery schedule, or both. Any changes in this quotation will be submitted and approved in writing.

B. **DELIVERY:** Typical delivery for catalyst and all equipment is within forty-five (45) weeks from the order date, contingent upon the timely return of approved drawings/documents. Storage fees will be charged if delivery is delayed beyond the project schedule for delays not caused by Peerless Mfg. Co. (Peerless). These charges will be imposed at the time of the delay.

C. **TRANSPORTATION:** Shipment of the equipment shall be via Motor Freight, Ex Works, Manufacturing Point. No allowance has been made for any freight charges, special packaging, or export packaging / crating.

D. **EXCLUDED ITEMS:** The quoted price does not include any custom duties, tariffs, import fees, income tax, nor any other taxes, duties, levies, etc., imposed by governmental organizations. Equipment delivered to the following states will require a Tax Exemption Certificate to exclude those current state taxes from our invoice: Arizona, California, Georgia, Kentucky, Tennessee, and Texas.

E. **VALIDITY:** The offered price is valid for thirty (30) days from the proposal date, and thereafter, is subject to our acceptance. Due to the current fluctuation in steel prices, all pricing in this proposal must be confirmed at time of purchase order.

F. **PAYMENT TERMS:**

G. **CHANGES / CANCELLATION SCHEDULE:** Any changes to or cancellation of the Agreement, once accepted, are subject to written approval by Peerless under conditions that shall include, among other things, protection against any loss to Peerless.

H. **WARRANTY:**

1. All hardware is under warranty for twenty-four (24) months from contracted delivery or eighteen (18) months from scheduled start-up, whichever occurs first. The extent of the warranty includes replacement of defective components, and is limited to material only.

2. Peerless is not responsible for any damage resulting from mis-operation or improper maintenance of the unit as described in the Peerless Operation & Maintenance Manuals for this project. Warranty is voided if the system is not operated and maintained in accordance with the Operation & Maintenance Manual.

3. The aqueous ammonia must be reagent grade, diluted with fully de-ionized water to 29% by weight.

CATALYST WARRANTY CRITERIA:

1. Each SCR catalyst bed performance is under warranty for thirty-six (36) months from initial start-up, or thirty-nine (39) months from contracted delivery, or 24,000 operating hours, whichever occurs first. This warranty is contingent on items discussed in the paragraph below and all requirements and contingencies provided by the SCR catalyst vendor.

2. The catalyst must be handled, operated, and maintained according to the catalyst vendor's instructions. Peerless is not responsible for any damage due to operation above or below temperatures or pressures other than those design conditions shown on the specification sheet provided by Peerless, nor any damage resulting from mis-operation or improper maintenance of the unit as described in the Peerless Operation & Maintenance Manuals for this project. The purchaser must give Peerless access to the relevant process operating logs if requested by Peerless.

3. To prevent premature thermal degradation of the SCR catalyst, the temperature at the catalyst face must not exceed 780 degrees F (416 degrees C). Exposure to excessive temperatures shall void the warranty.

4. The SCR catalyst face temperature must be a minimum of 450 degrees F (232 degrees C) for natural gas and 550

degrees F (288 degrees C) for oil before ammonia injection will be allowed.

5. Unit operating conditions shall be within the limits of design cases provided.

6. The catalyst vendor maintains warranty protection as long as normal system start-up and shut-down procedures are followed and no moisture other than from the flue gas or ambient air is present. The allowed start-up and shut-down temperature gradient for the catalyst is 10ºC/min below and 100ºC/min above the flue gas dew point.

7. The catalyst vendor is not responsible for catalyst degradation caused by reagent drainage or other liquid contact to catalyst.

8. The catalyst vendor is not responsible for catalyst degradation caused by catalyst poisons. Design for natural gas applications is based on impurities found in typical United States pipeline quality natural gas applications. Impurities in the exhaust flue gas were not available for evaluation. The impact of impurities can significantly impact the proposed design. A fuel specification including trace components must be provided to ensure that the catalyst design is adequate for the application.

   a. Fine Particulate (ash)
   b. Ammonia-Sulfur Compounds
   c. Alkaline Metals (Family includes sodium, potassium, cesium, lithium, francium, rubidium)
   d. Alkaline earth metals (Family includes calcium, magnesium, barium, strontium)
   e. Non-Metals (phosphorus, arsenic, silicas, siloxanes)
   f. Halogens (fluorine, chlorine)
   g. Transition and Other Metals (Family includes iron, antimony, chrome, copper, lead, mercury, nickel, tin, zinc, vanadium, platinum, rhodium, palladium)

   In the event that the catalyst contains, either singularly or collectively, levels of the above contaminants in excess of 450 mg / m3 or 15 mg / ft3 (as determined by ICP-OES, or glow discharge mass spectrophotometry) then the warranty shall be voided.

9. If applicable, Purchaser shall clean catalyst masked or plugged by firing of particulate producing fuel discovered by means of periodic visual inspections.

10. Purchaser must provide catalyst samples to Peerless, if requested during the warranty period, in order to maintain warranties. Seller will provide an advance written request of a need to obtain catalyst samples, construction and sampling method that permits ease of extraction and replacement of samples, and schedule coordination for the operating plant's convenience.

11. Purchaser will provide a copy of all procedures and methods of analysis to be employed in catalyst evaluation for Acceptance and anytime throughout the warranty period.

12. The NO/NOx ratio must be greater than 0.50 at the AIG and SCR catalyst inlet for optimum pertormance and NOX reduction warranties to be met. (NO_2 speciation must be less than or equal to 50% of the total NOx.)

13. The temperature profile at the AIG and catalyst must be less than +/- 20 degrees F (+/- 11 degrees C) of the average for optimum performance and NO_X reduction warranties to be met.

14. The flow velocity profile at the AIG and catalyst must be +/- fifteen percent (15%) RMS normal for optimum performance and NO_X reduction warranties to be met.

15. **No** ammonia oxidizing material, such as platinum group elements, is to be dispersed upstream of the SCR reactor.

16. Peerless will not accept spent catalyst as part of the disposal process. Catalyst disposal is the responsibility of others.

CATALYST WARRANTY FULLFILLMENT REMEDY

In the event that the Purchaser suspects the catalyst to be in non-compliance with the Contract and subsequent on-site tests during the warranty period indicate that the warranted values are not being met, Peerless will conduct an on-site investigation to determine the cause of non-performance. If the catalyst is suspect, Peerless will conduct laboratory tests, according to the conditions specified in the Technical Specifications, to verify the catalyst performance. The costs for the Peerless' on-site investigations and subsequent testing shall be born by Peerless.

If the results of the laboratory tests indicate that the warranted values are being met, or Peerless' Subcontractor(s) warranties will be deemed in fulfillment at this time and Purchaser will continue their investigation to determine the cause of non-fulfillment. In this event, Purchaser will compensate Peerless for the cost of laboratory evaluation.

If the results of the laboratory tests indicate that the warranted values are not being met during the first (1st) through the twelfth (12th) month of operation, Peerless shall have the option to:

a) Replace the non-performing catalyst at Peerless' expense; or
b) Repair the non-performing catalyst at Peerless' expense.

Warranty remedies include the cost of the replacement catalyst or catalyst repair and shipping costs to and from the jobsite only. The cost of labor and lifting equipment, if required, to perform the removal and installation of catalyst covered by warranty is not included and is to be provided by the Purchaser.

In the event the Catalyst fails to perform as described above during the thirteenth (13th) through the guaranteed month of operation, Peerless shall have the option to:

(a) Replace the non-performing Catalyst with Peerless responsible for that proportion of the replacement catalyst price equal to guaranteed service hours minus the number of hours since start-up, divided by guaranteed service life (i.e., XX months.-N) / XX months); and Owner responsible for the balance. (For example, if the Catalyst fails to perform during the XX months of operation, then Contractor would be responsible for ((XX – N months) / XX months = XXX) of the replacement price)); or
(b) Repair the non-performing Catalyst with Peerless responsible for that proportion of the repair equal to guaranteed service months minus the number of months since start-up, divided by guaranteed service months; and the Owner responsible for the balance.

Warranty remedies include the cost as stipulated above of the replacement catalyst or catalyst repair and shipping costs to and from the jobsite only. The cost of labor and lifting equipment, if required, to perform the removal and installation of catalyst covered by warranty is not included and is to be provided by the Purchaser.

Peerless' warranties are fulfilled at the end of the period stated in this proposal if the results of on-site tests indicate that the performance values shown in this proposal are met.

I. PROPRIETARY RIGHTS:

1. All engineering and application information given in Peerless' Proposal is proprietary. Such information is to be used only in the evaluation of this offer. If an order does not result from this Proposal, such proprietary information must be held in confidence, and never used in any manner by the prospective purchaser.

2. If an order results from the Proposal, such proprietary information becomes the property of the Purchaser for use in the design, manufacture, and operation of the specific unit proposed, and cannot be used on any other item or in any other manner without approval from Peerless.

J. NON-UNION LABOR: All Peerless labor facilities are non-union. Non-union employees will complete all Peerless fabrication work. UA labeled pipe can be supplied for an additional cost, if required.

III. GENERAL SCOPE OF SUPPLY

DESCRIPTION	Peerless	Optional	Buyer	Out of Scope
BASIC ENGINEERING AND DESIGN				
Drawing and Document Index (if requested)	X			
P&IDs	X			
System Control logic (SAMA diagrams)	X			
Component Specification	X			
ISA Datasheets	X			
Paint Specification	X			
Piping Specification	X			
I-O List	X			
Dilution air or exhaust blower & motor data (includes fan curves, motor drawing, motor wiring diagrams, motor performance sheet, cut sheets of auxiliary equipment)	X			
Inspection and Test Plan	X			
Utility Consumption List (includes electricity and air users)	X			
Weld Procedures and Supporting PQRs	X			
Spare Parts List	X			
Shipping Bill of Material	X			

Operation & Maintenance manuals – eight (8) CD copy and two (2) hardcopies. Additional hardcopy manuals are $100.00 each. (Vendor data sheets are provided on CD-ROM only in English.)	X			
Equipment general arrangement drawings (including location of anchor bolts)	X			
Design of anchor bolts (size and length)			X	
Design of insulation (if applicable)	X			
Supply and installation of insulation (if applicable)			X	
PE Stamp (can be included for an additional cost)		X		
Design, supply, and installation of heat tracing or instrument protection (if applicable)			X	
Computation Fluid Dynamics (CFD) Modeling		X		

DESCRIPTION	Peerless	Optional	Buyer	Out of Scope
AMMONIA SYSTEM				
Aqueous Electric Ammonia Flow Control Unit:				
Ammonia Flow Control Train				
Y-type strainers (2 x 100%)	X			
Manual isolation valves (ball or gate) – multiple	X			
Differential pressure gauge across strainers (one)	X			
Pressure gauge (one)	X			
Coriolis style flowmeter/transmitter (one)	X			
Ammonia Flow Control Valve (one)	X			
Actuated ball valve (shut-off valve) (one)	X			
Dilution Air Line				
Ambient air blowers and motors (2 x 100%) (480V, 3-Phase, 60 Hz power)	X			
Power wiring for fan motors			X	
Filter-silencers (2 x 100%) – on inlet of each blower	X			
Annubar style flowmeter/transmitter (one)	X			
Butterfly valve (manual) (one per blower – on outlet of blower)	X			
Check valve (manual) (one per blower – on outlet of blower)	X			
Pressure gauge (one)	X			
Motor starters (Main disconnect breaker is not included)			X	
Ammonia Vaporization and Dilution Chamber (1 x 100%) Chamber is a counter-current flow packed tower. Chamber Material: SA-36 * Atomizing air is not required. ** ASME code design is not required.				
Immersion style electric heater (1 x 100%)	X			
Heater power panel (1 x 100%)	X			
Pressure gauge (one)	X			
Thermocouple and thermowell (at vaporizer sump) (one)	X			
Temperature transmitter (at vaporizer sump) (one)	X			
Thermocouple and thermowell (at vaporizer sump) (one)	X			
Temperature transmitter (at vaporizer sump) (one)	X			
Instrument Air Line				
Manual isolation valves (ball valves) – (multiple)	X			
Junction Box (one – houses analog instrument signals, discrete instrument signals, and 120VAC instrument power)	X			
Foundation / Support of AFCU			X	

Supply of external insulation for AFCU			X	
Installation of external insulation for AFCU			X	
Supply and installation of heat tracing for AFCU			X	
PLC Local Control Panel:				
Peerless Standard PLC Control Panel Allen Bradley CompactLogix PLC • PLC Controller o Analog Input (4-20mA) o Analog Output (4-20mA) o Analog Thermocouple Input o Digital Input /Output o Serial Data Comm (to HMI) • HMI –10" Color Touchscreen • Enclosure – Painted CS, NEMA 4 • Bebco Purge system for Class I, Div 2 area classification • Standard terminals, wire, and accessories. **Options:** • PLC processor with Ethernet comms and a 5-port industrial Ethernet switch for HMI and DCS comms (Add $3,170) • Upgrade from 10" to 12" PanelView Plus Color Touch-screen (Add $1580) • Upgrade from 10" to 12" High-Bright, UV Protected, PanelView Plus Color Touch- screen (Add $2,660)		X		
Manifold:				
Ammonia injection manifold Orientation: Vertical on one side Material: A-53B carbon steel welded pipe	X			
Expansion joints in main header (as required)	X			
Pressure gauge (near manifold inlet)	X			
Orifice plate at each branch take-off	X			
Throttling valve (butterfly or gate valve) at each branch take-off	X			
Isolation valve (gate valve) at each branch take-off				X
Differential pressure indicators at each branch take-off	X			
Tubing and fittings for plumbing differential pressure indicators to orifice plates (tubing is shipped loose, in bulk, to job site for field erection)	X			
Insulation			X	
Supports for manifold			X	
Ammonia Injection Grid:				
Ammonia injection grid (EDGE™): Each branch of ammonia injection grid is shipped loose for field installation Material: Carbon Steel - Tube Steel	X			
Interconnecting Piping: *Supply of interconnecting piping is based on the AFCU being within 25 feet of the ammonia injection location. Supply is based on no site obstructions that would require additional elbows or piping.*				
Interconnecting pipe (AFCU to manifold)			X	
Interconnecting pipe (Manifold to AIG)			X	
Insulation			X	
Support of interconnecting piping			X	

DESCRIPTION	Peerless	Optional	Buyer	Out of Scope
CATALYST				
SCR catalyst bed	X			
SCR catalyst test coupons	X			

DESCRIPTION	Peerless	Optional	Buyer	Out of Scope
DUCTWORK AND STRUCTURE				
AIG support structure	X			
SCR catalyst support structure & sealing mechanism Material: Carbon Steel	X			
CO catalyst support structure & sealing mechanism				X
Expansion Joint at Boiler Exhaust			X	
Flow distribution correction (if required)			X	
Inlet transition ducting to reactor housing			X	
Expansion joint at reactor housing inlet			X	
Reactor Housing (including lifting lugs with dead load limit, lifting plan by others) Duct Casing Material: Carbon Steel Casing Thickness: 0.25" minimum Internal Liner: 409 S/S (14 ga. - walls and ceiling; 12 ga. - floor) Internal Insulation: 8 lb/ft^3 ceramic fiber blanket – 4" thickness Casing Design temperature is < 140ºF at XX F and XX mph wind	X			
Expansion joint at reactor housing outlet			X	
Outlet ducting from reactor housing			X	
Reactor housing structural support steel			X	
Test Ports for Catalyst	X			
Reactor instrumentation Differential Pressure Transmitter Temperature Transmitter Note: Instrumentation is shipped loose and installed in the field by others. Note: Includes instrument trim / fittings / drains	X			
Manual Hoist / Manual Trolley Includes chain hoist, gear driven manual trolley, and chain bucket	X			
Catalyst installation / access door	X			
Ductwork platforms and ladder access				X
Stack			X	
CEMS test ports			X	
Stack platform and ladders Material: Galvanized			X	
Silencer			X	

DESCRIPTION	Peerless	Optional	Buyer	Out of Scope
GENERAL				
Supply of anchor bolts			X	
Supply and installation of external insulation			X	
Supply and installation of heat tracing			X	

DESCRIPTION	Peerless	Optional	Buyer	Out of Scope
SITE WORK				
Field Service / Supervision		X		
Interconnecting wiring, ground frames, and conduits			X	
Electrical supply and controls for pumps, fans			X	
Final field and touch-up painting			X	
Unloading and storage at job site			X	
Civil/foundation design and work, anchor bolts and frames			X	
Labor, equipment, consumables, and materials for erection of the equipment at the job site			X	

IV. PEERLESS STANDARD DESIGN SPECIFICATIONS:

Paint Specification:
Surface Preparation: SSPC SP-6, Commercial Blast Cleaning
Primer: Inorganic Zinc Primer, Carboline, Carbo Zinc 11, Gray #0700, 2-3 mils DFT
Top Coat: Carboline Carbothane 133HB, 2-2.5 mils, 4701 Gray White Color
** Applies to all CS surfaces that are not ultimately insulated (either in Peerless' shop, other shop, or in the field):*
*** All stainless steel surfaces (ferric or austenitic) will be SSPC SP-1 solvent cleaned only.*
**** Valves will not be painted (primer or top coat) regardless of material of valve or material of line in which the valve is installed*

Piping Design, Fabrication, and Testing Specifications:
Aqueous Ammonia Systems: ASME/ANSI B31.3
** Please note the AIG lances are considered specialty equipment, not piping, and therefore are not subjected the above design codes.*

All structural welding (e.g., AFCU skid base) will be designed, fabricated, and tested to ASME code, Section IX

Electrical Classification:
Enclosure Type: NEMA 4X
IEC Enclosure Class: IP56
Area Classification: Hazardous - Class I, Division II, Groups B and C

Native format of all drawings: AutoCAD 2006
Native format of all documents: Microsoft Word, Excel, Adobe Acrobat
** Please note all drawings and documents will be officially submitted in Adobe Acrobat format*

Peerless Standard Instrument Suppliers:

Component	Standard Supplier	Technically Acceptable Alternates *(Additional cost may apply)*
Dilution Blower (high temp exhaust)	Robinson	
Dilution Blower (ambient air)	Chicago Blower, Rotron/Ametek	
Dilution Blower motors (either type)	TECO Westinghouse	Reliance, Baldor, Siemens, GE
Electric heater (flanged immersion style)	Chromalox	Watlow, CCI Thermal
Electric heater power panels	Peerless	Chromalox
Valves – Gate (forged, smaller than 2")	Vogt	Powell, Velan
Valves – Gate (cast, 2" and larger)	Powell	Velan, Vogt
Valves – ball	Marwin	Velan, KF Contromatics, Metso (Jamesbury)
Valves – check (wafer style)	Crane	Champion
Valves – butterfly	Keystone	WKM
Valves – globe	Velan	Vogt
Damper	Advanced Valve Design	Shanrod
Thermocouple/thermowell	Rosemount	STI
RTD/thermowell	Rosemount	STI
Temperature indicator (thermometer)	Wika	Ashcroft
Temperature transmitter	Rosemount	Honeywell
Temperature Switch	SOR	
Pressure gauge	Wika	Ashcroft, 3D Instruments
Differential pressure gauge	Midwest	Ashcroft
Pressure transmitter	Rosemount	Honeywell
Differential pressure transmitter	Rosemount	Honeywell
Pressure switch	SOR	Ashcroft
Flowmeter/transmitter (ammonia) – coriolis	Micromotion	
Flowmeter/transmitter (ammonia) – thermal	Brooks	
Flowmeter/transmitter (dilution media) –annubar	Rosemount	Veris
Flow Switch (dilution media)	SOR	
Orifice plates	Fluidic Techniques (Vickery-Simms)	Primary Flow Signal, Triad, Daniel Industries
Flow control valve (ammonia line) • Valve • Actuator (pneumatic) • Positioner (I/P) • Air regulator	 Fisher-Baumann Baumann Fisher Fisher	
Actuated Damper (exhaust line) • Damper • Actuator (pneumatic) • Solenoid valve • Limit Switches • Air regulator	 Advanced Valve Design Tyco-Morin ASCO Westlock Fisher	 Shanrod Fisher (Field Q) Burkett Topworx, Tyco-Avid SMC
Actuated ball valve (ammonia line) • Valve • Actuator (pneumatic) • Solenoid valve • Limit switch • Air regulator	 Marwin Tyco-Morin ASCO Westlock Fisher	 Velan, KF Contromatics, Metso (Jamesbury) Rotork Burkett Topworx, Tyco-Avid SMC

Needle Valves	AGCO	Hex
Instrument Root Valves	AGCO	Hex
Instrument Manifold Valves	AGCO	Hex
Pressure regulator	Fisher	
Strainers	Armstrong	
Expansion Joints (metallic)	American Boa	Unaflex
Expansion Joints (rubber)	General Rubber	
Expansion Joints (fabric)	Johnson Expansion Joints	
Excess flow check valve	MGM	Rego
Level Indicator (float style)	Rochester	
Level indicator (bridled, magnetic flag style)	Magnetrol	K-TEK, Jerguson
Level Transmitter (guided wave radar style)	Magnetrol	Rosemount
Flow sight glass (unloading station)	Penberthy	
Remote level indication (unloading station)	Rosemount	
Pressure relief valve (vapor ammonia)	Crosby	Rego, Farris
Hydrostatic relief valve (liquid ammonia)	Rego	Crosby
Vacuum breaker valve (storage tank)	Groth	
Emergency shut-off valve (unloading station)	Fisher	Rego
Ammonia gas detectors	Scott Instruments	
Junction boxes	Peerless	
PLC's	Allen Bradley (Compact Logix)	GE Fanuc (9030 series)

**Peerless reserves the right to provide alternate suppliers.*

V. DESIGN CRITERIA

A. DESIGN CONDITIONS: The proposed SCR System design is based on the following design conditions; the data is for one (1) unit. Should the actual gas conditions be different from the design data, the performance shall be re-evaluated, based on the corrected design data.

	Case:	1	2				
	Fuel:	NG @ 15% XS Air	NG @ 15% XS Air				
Reactor Inlet Conditions:							
Flue Gas Flow Rate, Wet	lb/hr	169,100	210,702				
Flue Gas Temperature	degrees F	697	701				
O2	Vol %, wet	2.50	2.50				
H2O	Vol %, wet	17.00	17.00				
N2	Vol %, wet	72.00	72.00				
CO2	Vol %, wet	8.50	8.50				
Ar	Vol %, wet	0.00	0.00				
NOx as NO2	ppmvd	29.0	29.0				
NOx as NO2	lb/hr	6.7	8.4				
NOx Reduction	Percent	75.9	75.9				
Dilution Air Required	lb/hr	327	327				
Dilution Air Required	SCFM	68	68				
Consumption NH4OH	lb/hr	12	15				
Consumption NH4OH	gal/month	1,098	1,368				
Total Mass Injected by SCR	lb/hr	339	342				
Reactor Outlet Conditions:							
Flue Gas Flow Rate, Wet	lb/hr	169,439	211,044				
Performance Warranties:							
NOx as NO2	ppmvd	7.0	7.0				
NOx as NO2	lb/hr	1.6	2.0				
NH3	ppmvd	5.0	5.0				
NH3	lb/hr	0.4	0.5				
Catalyst Bed Pressure Drop	" W.C.	See Catalyst Section					
"ppmvd" denotes parts per million by volume, dry, referenced to 3 percent oxygen.							

B. CATALYST DESIGN DETAILS:

SCR CATALYST DATA			
Catalyst Manufacturer	Cormetech	Haldor Topsoe	Equal (with Buyer approval)
Catalyst Type	Honeycomb Ceramic Vanadium / Titanium	Honeycomb Vanadium / Titanium	Honeycomb or Plate Vanadium / Titanium
Gas Flow	Vertical up	Vertical up	Vertical up
Number of Modules	9	8	TBD
Arrangement	1 x 9 x 1	1 x 8 x 1	TBD
Module Size W x D x H	101" x 17" x 38.625"	93" x 13.2" x 37.3"	TBD
Total Catalyst Weight	10,800 lb	4320 lb	TBD
Estimated Gas Path Requirement W x H	8.75' x 29.75'	9.2' x 29.75'	TBD
Guaranteed Pressure Drop	≤0.5 "H_2O @ Case 2	≤0.5 "H_2O @ Case 1	TBD

C. UTILITY CONSUMPTION (AQUEOUS ELECTRIC AMMONIA FLOW CONTROL UNIT):

DESCRIPTION	QUANTITY	UNITS
Design Flow Rate **Aqueous Ammonia** (19% by Weight)	≤20	Lbs/Hr/Unit
Ammonia Supply Pressure	40	PSIG
Ammonia Inlet Temperature	Ambient	F Minimum for NH_3
Ammonia Inlet Temperature	Ambient	F for NH_4OH
AFCU Electric Air Heater		
Capacity	15	kW
Consumption at Maximum Operating Ammonia Flow Rate (Estimated)	TBD	kW
Instrument Air (-20 F Dew Point or Better)		
Supply Pressure	80-125	PSIG
Maximum Steady State Air Consumption	1	SCFM
Maximum Instantaneous Air Supply Demand	5	SCFM
AFCU Dilution Air Blowers		
Nominal Motor Rating (Estimated Only)	3	HP
Operating Power Consumption (Estimate)	75% of rated capacity	BHP

VI. LIST OF DOCUMENTS RECEIVED WITH INQUIRY:

Peerless has designed the equipment in accordance with the following specifications with exception to the items listed under Section VI of this proposal. Referenced specifications will be considered only if copies are provided with the proposal inquiry. State and local codes and/or regulations will be considered only if applicable copies are attached to the proposal inquiry.

- P138431A-SCRds-Rev00-2.pdf

VII. TECHNICAL CLARIFICATIONS AND EXCEPTIONS, GENERAL:

- None noted at this time. To be discussed further.

VIII. COMMERCIAL CLARIFICATIONS AND EXCEPTIONS, GENERAL:

- Commercial Terms and Conditions were not included with the inquiry documents. This proposal is based on Peerless Mfg. Co. terms and conditions.

IX: DESIGN NOTES / ANSWERS TO FREQUENTLY ASKED QUESTIONS:

1. Required Control Input Signals (by others): load signal, CEMS output signals, inlet analyzer signals

X. PEERLESS STANDARD TERMS AND CONDITIONS:

1. PRICE. Unless otherwise specified in this Quotation, prices exclude all taxes (imposed by any state, country or other governmental entity), duties, packing and freight costs (including, without limitation, the cost of loading goods on board a carrier) and related costs and expenses, all of which shall be added to such prices and paid by Buyer. In addition, Buyer shall pay, or reimburse Seller for, reasonable out-of-pocket expenses, including, without limitation, travel and travel-related expenses, incurred by Seller in connection with the performance of its obligations or incurred by Seller at the request or with the approval of Buyer. Should Buyer request any change in goods or services covered by this Quotation, Seller shall not be obligated to proceed with such change until Seller agrees in writing to proceed with such change. If Seller determines that any such change may cause an increase in Seller's costs or the time required for provision of goods or services, or may raise other issues of concern to Seller, an equitable adjustment shall be made with respect to price, schedule or otherwise in order to address such issues.
2. PAYMENT. Unless otherwise specified in this Quotation, payment for goods and services covered by this Quotation shall be made, in cash, within thirty (30) days from date of Seller's invoice. Unless otherwise specified in this Quotation, U.S. dollars shall be the currency of account, for all purposes, with respect to this Quotation. Amounts not paid when due by Buyer shall bear interest at the highest lawful rate on the unpaid amount from the due date until paid; provided, however, extended payment terms are acceptable only if agreed upon in writing by Seller.
3. SCHEDULES. All dates or schedules specified in this Quotation are approximate and are based upon Buyer's and other parties' timely provision of information, and performance of related work and obligations, necessary for Seller to perform its obligations hereunder. Seller shall be excused from any failure to meet such dates or schedules, where such failure is occasioned by any of the circumstances or conditions enumerated in paragraph 13 below. If any failure to meet dates or schedules is occasioned by the fault of Seller, Seller shall make commercially reasonable efforts to remedy such failure as soon as reasonably practicable. Any installation or use of goods or services by Buyer shall constitute a waiver of all claims for delay. Seller has the right to deliver goods at one time or in installments, from time to time, within the period provided for delivery. In the event of partial shipments, Seller may immediately invoice Buyer for the amount(s) due in respect thereof, which amount(s) shall be due and payable in accordance with paragraph 2 above. Delivery of nonconforming goods, or a default of Seller of any nature in relation to one or more installments, shall not substantially impair the value of this transaction, as a whole, and shall not constitute a default hereunder, as a whole.
4. SECURITY INTEREST. Seller shall retain, and Buyer hereby grants to Seller, a security interest in goods covered by this Quotation, now owned or hereafter acquired, wherever located, including all returns, repossessions and parts, and all chattel paper, instruments, documents, accounts, general intangibles, contract rights and security agreements (resulting from the sale or other disposition of such goods) and all cash and non-cash proceeds of any of the foregoing, which shall secure the payment of all amounts due from Buyer to Seller as specified in this Quotation. Buyer shall, at the request of Seller, execute, and hereby grants Seller the right to execute in the name of Buyer, any documents necessary to grant to Seller a security interest in such goods and any filings necessary to perfect such security interest in all jurisdictions where Seller deems such filings to be necessary to protect its interest.
5. INSPECTION. Buyer shall have the right to inspect goods fabricated hereunder prior to acceptance provided (i) such inspection shall occur at the place of fabrication, during the period of fabrication, (ii) such inspection shall be conducted by an authorized and qualified representative of Buyer, during normal working hours after reasonable notice to Seller and without interference with operations, (iii) Buyer shall ensure that all persons involved in such inspection comply with applicable security and other procedures relating to the place of fabrication and (iv) Buyer shall promptly notify Seller, in writing, in the event that any person involved in such inspection shall discover any defects or other problems with respect to the goods. Any inspection at the facilities of a supplier or subcontractor of Seller shall be subject to securing permission from such supplier or subcontractor, and Seller shall make commercially reasonable efforts to obtain such permission. Buyer shall accept goods, or part thereof, as soon as they are reasonably tendered to Buyer, unless during inspection at the place of fabrication Buyer has notified Seller of the unacceptability of such goods and confirms such notice in writing within ten (10) days of such inspection, but not later than the regularly scheduled shipment of such goods. Buyer may not revoke its acceptance. This paragraph 5 in no way modifies or affects Buyer's remedies or Seller's warranties set forth elsewhere in this Quotation.
6. INSTALLATION/SERVICE. Unless otherwise specified in this Quotation, all goods shall be installed by and at the expense of Buyer. If so specified in this Quotation, Seller shall furnish technical personnel to assist in installation and start up of goods, in which case Buyer shall pay Seller, at Seller's then current commercial billing rates, for the resources utilized in connection with such assistance. In the event of service calls, exclusive of service calls necessitated by Seller's beach of the warranties set forth elsewhere in this Quotation, Buyer shall pay Seller, at Seller's then current commercial billing rates, for the resources utilized in connection with such service calls.
7. SPECIFICATIONS. In the event Buyer is to specify the form, measurement, features or other specifications for goods, or to provide other information with respect to goods or services, Buyer shall deliver and secure Seller's written acceptance of such information on or before the agreed date or, if no date has been agreed upon, within a reasonable time after receipt of a request from Seller. Seller's quality assurance and other procedures, specifications and drawings, as approved Buyer, shall be deemed for all purposes to comply with any procedures, specifications and drawings of Buyer and to supersede any conflicting terms thereof.
8. COOPERATION. Buyer shall cooperate with Seller in connection with Seller's performance of its obligations through, among other things, performing its responsibilities set forth in this Quotation, securing performance of related work by other parties and making available, as reasonably requested by Seller, access, management decisions, information, approvals and acceptances in order that Seller may perform its obligations in a timely manner.
9. WARRANTIES.

a) General. Seller warrants to Buyer that, under normal use, each item of goods covered by this Quotation shall be free from defects in workmanship and material for a period of twelve (12) months from the date of installation or eighteen (18) months from date of shipment, whichever occurs first. In the event this Quotation specifies a performance warranty or guaranty, Seller warrants to Buyer that, under normal use, each item of goods covered by this Quotation shall perform, in all material respects, in a manner consistent with such performance warranty or guaranty for the period specified in such performance warranty or guaranty or, if no such period is specified, for the period specified in the immediately preceding sentence. "Normal use", as used herein, includes only such uses under such conditions as have been fully disclosed, in writing, to Seller prior to the date of this Quotation. In addition, Seller warrants to Buyer that Seller shall use reasonable care in providing services covered by this Quotation and that such services shall be provided in a workmanlike manner. In the event there are any nonconformities with these warranties, which nonconformities are reported by Buyer to Seller during the applicable warranty period, Seller shall promptly repair or replace the nonconforming goods and re-perform the nonconforming services.. In the event Buyer claims a nonconformity with these warranties, Seller or its appointee shall have the right to finally approve or disapprove such claim. In each instance of nonconforming goods, Buyer may elect, at its option, to (i) return goods, or part thereof, covered by this Quotation and to which the nonconformity relates, to Seller, at Seller's fabrication facility, risk of loss en route to Seller's facility to lie with Buyer, for Seller's inspection and approval or disapproval or (ii) demand an on-site inspection of such goods. If Seller approves a claim, all transportation costs and other incidental costs incurred in Seller's inspection of the goods, or part thereof, shall be borne by Seller; otherwise, Buyer shall bear all such costs.

b) Exceptions. Notwithstanding anything to the contrary, if any nonconformities with these warranties arise, in whole or part, as a result of work performed by, or the act or omission of, Buyer or any other party, the maintenance or modification of goods other than by Seller, Vendor Items (as hereinafter defined), operation or use of goods or services in a manner inconsistent with any design conditions or other than as anticipated by applicable specifications or other than in accordance with operating instructions provided by Seller, failure to maintain catalyst and other consumables in accordance with manufacturer recommendations or any services, software, equipment or other items provided by Buyer or a third party, such nonconformity shall not constitute a nonconformity with these warranties and Seller shall not be responsible therefor. Notwithstanding anything to the contrary, and except as otherwise specifically agreed in writing by Seller, Seller shall have no responsibility for suggesting, specifying or confirming the appropriateness of Buyer's specification of any goods, materials or other items used in the fabrication of goods or any other thing and no warranty in respect thereof is made by Seller. No failure which directly or indirectly relates, in whole or part, to such goods, materials or other items shall be, in any respect, the responsibility of Seller or a nonconformity with these warranties. These warranties shall not apply to any goods, materials, items or services supplied to Seller by Buyer. Seller hereby assigns to Buyer any warranties given by Seller's suppliers or subcontractors ("Vendors") in connection with any goods, materials items or services obtained by Seller from such Vendors ("Vendor Items") and included as a part of goods or services covered by this Quotation, to the extent such warranties are so assignable at no additional cost to Seller. To the extent that any such warranties are not assignable, Seller shall, upon the written request of Buyer and at Buyer's expense, take commercially reasonable actions to enforce any applicable warranty which is enforceable by Seller in its own name. However, Seller shall have no obligation to resort to litigation or other formal dispute resolution procedures to enforce any such warranty. With the exception of applicable Vendor's warranties which Seller is able to pass through for Buyer's benefit, Vendor Items are provided on an "AS IS" basis without warranty and, notwithstanding anything to the contrary, Buyer agrees to look solely to the applicable Vendor for any and all warranty claims respecting Vendor Items.

c) Disclaimer. THESE WARRANTIES ARE EXPRESSLY IN LIEU OF ALL OTHER EXPRESS OR IMPLIED WARRANTIES, INCLUDING ANY IMPLIED WARRANTY OF MERCHANTABILITY, FITNESS, TITLE OR NONINFRINGEMENT OF ANY PATENT OR OTHER PROPRIETARY RIGHT AND OF ANY OTHER OBLIGATION ON THE PART OF SELLER, except as may be otherwise specified in this Quotation. Other warranties specified in this Quotation, if any, are strictly limited to their respective terms and in no way modify, alter, or waive the general effect of this disclaimer as to all other express or implied warranties. No agent, distributor or representative of Seller has any authority to bind Seller to any affirmation, representation or warranty, either written or oral, concerning goods or services covered by this Quotation or any other matter or thing and, unless an affirmation, representation or warranty made by an agent, distributor or representative is specifically included within this

Quotation, it shall not be enforceable by Buyer. The remedies set forth in this paragraph 9 constitute Buyer's sole and exclusive remedies for any nonconformity with these warranties.

d) Suspension. Notwithstanding anything to the contrary, Seller's may, at its option, suspend performance under this paragraph 9 in the event Buyer is not in full compliance with this Quotation and its obligations hereunder. While, during any such suspension, Seller shall have no obligations under this paragraph 9, such suspension shall not result in any extension of applicable warranty periods or otherwise modify these warranties.

10. BUYER'S REMEDIES. Buyer's exclusive and sole remedies, except as provided in paragraph 9 above, for any default hereunder by Seller, are strictly limited to either, at Seller's option, (a) refund of the price paid by Buyer for goods and services in question and return of such goods to Seller or (b) repair and/or replacement of nonconforming goods, or parts thereof, and re-performance of nonconforming services. Notwithstanding anything to the contrary, in the event this Quotation provides for liquidated damages or any other spacified amount to be paid, or indemnification or any other specified action to be taken, by Seller, such amount or action shall constitute Buyer's sole and exclusive remedy for the circumstance or condition upon which such amount or action is based. Under no circumstances shall (i) Buyer have the right to claim or recover any punitive, exemplary, incidental or consequential damages or (ii) Seller be liable, in the aggregate for any and all matters arising out of, under, or in connection with this Quotation, whether based on an action or claim in contract, equity, negligence, intended conduct, tort or otherwise, for more than the amount paid by Buyer for goods and services covered by this Quotation.

11. SELLER'S REMEDIES. All of Seller's remedies set forth in this Quotation, in the event Buyer fails to comply with this Quotation or any of its obligations hereunder, shall be cumulative and in addition to, and not in lieu of, any other remedies available to Seller at law, in equity or otherwise, and may be enforced concurrently or from time to time and Seller shall additionally be entitled to recover its reasonable attorney's fees and costs incurred by Seller in the enforcement of its rights and remedies. Without limiting the foregoing, in the event Buyer fails to make one or more payments when due, or otherwise defaults in the performance of any of its obligations, Seller may, at its option, suspend performance hereunder until such default is cured or terminate its obligations hereunder, or both.

12. RISK OF LOSS AND PASSAGE OF TITLE. Unless otherwise specified in this Quotation, all goods to be delivered by Seller are sold ex works (as defined in Incoterms 2000, ICC Publication NO. 460) and title to such goods shall pass to Buyer at the earlier of (i) the date when Buyer obtains physical possession of such goods or part thereof or (ii) the date such goods are loaded on a carrier for delivery to Buyer. If no carrier is specified by Buyer sufficiently in advance of the required date(s) of shipment, Seller may select any mode(s) of transportation and any common carrier satisfactory to Seller and such selection shall conclusively be deemed satisfactory to Buyer. In the absence of a written agreement to the contrary, Buyer bears all risks of shipment of any goods sold hereunder.

13. FORCE MAJEURE. Seller shall be excused from performance hereunder for any period, and to the extent, that it is hindered or prevented from performing pursuant hereto, in whole or in part, as a result of delays caused by Buyer or third parties, floods or other acts of God, war, revolution, terrorism or civil disturbance, governmental action, statute, ordinance or regulation, court order, strike or other labor dispute, fire, damage to or destruction in whole or in part of goods or place of fabrication, lack or inability to obtain raw materials, labor, fuel or supplies or any other circumstances or conditions beyond Seller's reasonable control. In the event of nonperformance occasioned by any of the foregoing circumstances or conditions, the time for performance shall be extended to the extent of such delay. Such nonperformance shall not be a default hereunder or a ground for termination hereof and shall not excuse Buyer from its payment obligations hereunder or extend the time for such payment.

14. VERIFICATION OF INFORMATION. This Quotation, including, without limitation, prices, schedules and specifications set forth herein, is based upon information furnished by Buyer to Seller. Buyer believes that such information is accurate and complete. However, if any such information should prove to be inaccurate or incomplete in any material respect, Seller may, at its option and by giving written notice thereof to Buyer, make appropriate adjustments to the provisions hereof including, without limitation, prices, schedules and specifications.

15. OWNERSHIP. Unless otherwise specified in this Quotation, Buyer shall not obtain any rights or interests in any patent, copyright, proprietary right or confidential know-how, trademark or process owned by Seller or any other party. Any and all intellectual property rights, including rights of patent, copyright and trademark, in any reports, drawings, documents, specifications, calculations, confidential know-how, materials, or processes (the "Intellectual Property Rights") owned or created by Seller and used or embodied in goods or services covered by this Quotation shall remain the sole property of Seller. Any and all Intellectual Property Rights developed by Seller, whether in the provision of goods and services covered by this Quotation or independently thereof, shall belong to Seller. Any and all right, title or interest that Buyer or any other party may have or obtain in or to Seller's Intellectual Property Rights is hereby assigned to Seller and Buyer shall take, or cause to be taken, all necessary or appropriate actions to vest such Intellectual Property Rights in Seller.

16. CONFIDENTIALITY. Buyer shall handle confidentially all designs and specifications and technical, commercial, financial and other information which Buyer receives from Seller pursuant to this transaction and shall not use, copy or communicate such information to others except in the performance of Buyer's obligations pursuant to this Quotation or as necessary for operation and use of the goods, without prior written consent of and the payment of fair compensation to Seller. If Buyer discloses such information to any other party, as permitted by this paragraph 16, Buyer shall secure such party's written agreement to the same confidentiality restrictions as stipulated herein and shall cause such party to comply with such confidentiality restrictions.

17. BUSINESS RELATIONSHIP. Seller, in providing goods and services to Buyer, is acting only as an independent contractor and under no circumstances shall Seller be deemed to be in any relationship with Buyer carrying with it fiduciary or trust responsibilities, whether through partnership or otherwise. Unless otherwise specified in this Quotation, Seller has the sole right and obligation to supervise, manage and direct the provision of all goods and services covered by this Quotation. Seller does not undertake by this Quotation or otherwise to perform any obligation of Buyer, whether regulatory or contractual, or to assume any responsibility for Buyer's business or operations. Buyer shall (i) accurately represent goods and services covered by this Quotation, including, without limitation, as to quality, function, purpose and compatibility, (ii) not attempt or purport to create any obligation of Seller with respect to goods, services or otherwise, (iii) not add, remove, obstruct, conceal, change or deface any notice, legend, logo, designation or other mark on, or affixed to, any goods or any packing or other materials provided with goods, (iv) permit operation, maintenance and use of goods only in accordance with, and in a manner anticipated by, applicable design conditions, specifications and operating instructions and (v) market and distribute goods and services only in the form provided to Buyer by Seller. Buyer shall indemnify, defend and hold Seller harmless from any and all damages, liabilities, costs, and expenses, including without limitation, reasonable attorneys' fees and expenses, arising out of, under or in connection with any claim, demand, charge, action, cause of action or other proceeding relating to the conduct of Buyer's business, including without limitation, the acquisition, transfer, operation and/or use of goods and services covered by this Quotation. This Quotation is not intended to confer any rights or benefits on any third party, including, without limitation, any employee, customer, business associate, creditor or affiliate of Buyer.

18. WAIVER. Waiver or nonenforcement by either Seller or Buyer of a right or privilege with regard to, or of a default by the other of, any term or condition of this Quotation shall not be deemed a waiver of future compliance therewith, and such terms or conditions shall remain in full force and effect.

19. ASSIGNMENT. Buyer shall not assign or transfer its rights or obligations under this Quotation, or any part hereof, without Seller's prior written consent.

20. HEADINGS. The headings contained in this Quotation are for reference purposes only and shall not in any way affect the meanings or interpretations hereof.

21. CHOICE OF LAW AND FORUM. This Quotation shall be governed by and construed in accordance with the laws of the State of Texas, without giving effect to principles of conflict of laws. The United Nations Convention on the International Sale of Goods shall not be applicable to this transaction. Any dispute that may arise out of or in connection with this transaction shall be subject to the exclusive jurisdiction of the courts of the State of Texas and the U.S. federal courts located in such state, and Buyer irrevocably submits to the personal jurisdiction of such courts for purposes of any suit, action or proceeding involving any such dispute.

22. ENTIRE AGREEMENT. The terms and conditions set forth in this Quotation constitute the entire agreement between the parties with respect to the subject matter hereof. This Quotation wholly cancels, terminates and supersedes any and all letters, requests for quotes, quotes, purchase orders, acknowledgments, bills of lading, agreements and understandings, whether oral or written, between Buyer and Seller with respect to the subject matter hereof. Terms and conditions set forth in any letter, request for quote, quote, purchase order, acknowledgment, bill of lading, agreement or other document utilized or exchanged by the parties shall not be incorporated herein or binding unless expressly agreed upon in writing by Seller. This Quotation may not be modified or terminated orally, and no modification, termination or waiver shall be binding on Seller unless accepted and acknowledged by a written instrument signed by a duly authorized representative of Seller.

23. EXPORTS. If all or any portion of the goods to be provided pursuant to this Quotation are to be exported from the United States, Buyer agrees that such exportation is subject in all respects to, and Buyer shall comply in all respects with, United States laws with respect to such export and subsequent re-export of such goods. Seller makes no representation or warranty relative to the export or re-export of such goods.

24. SURVIVAL. All representations, warranties, covenants and indemnities made in this Quotation shall survive the consummation of the transactions contemplated by this Quotation. Termination of all or any part of this Quotation, for any reason, shall not release Buyer from any liabilities or obligations set forth in this Quotation which (i) expressly survive any such termination or (ii) remain to be performed or by their nature would be intended to be applicable following any such termination.

25. SAVINGS CLAUSE. If any provision of this Quotation is declared or found to be illegal, unenforceable or void, then obligations arising under such provision shall be null and void and each provision not so affected shall be enforced to the full extent permitted by law.

26. ARBITRATION. Any controversy arising out of this transaction shall be finally settled by arbitration. The arbitration shall be carried out pursuant to the commercial arbitration Rules of the American Arbitration Association then in force by one or more arbitrators appointed in accordance with such rules. The arbitration shall take place in Dallas, Texas, U.S.A., and the award shall be deemed a State of Texas award. The English language shall be used in the arbitration proceedings. The award shall be made and shall be payable in U.S. dollars free of any tax or other deduction. The award shall include interest from the date of any breach or other violation of this Agreement to the date when the award is paid in full at an appropriate rate of interest fixed by the arbitrators. Judgment upon the award may be entered in any court of appropriate jurisdiction.

XI. START-UP SUPPORT AND FIELD SERVICE RATES (DOMESTIC):

DOMESTIC FIELD SERVICE RATE SHEET (Effective 3/1/09)
FIELD SERVICE includes inspection, direction of installation or repair (labor by others), startup, initial adjustments, readjustment, test and general inspection of plant personnel for the operation and maintenance of Peerless Mfg. Co.'s and related equipment in a plant system. The field service is performed by Peerless Mfg. Co.'s Authorized Service Representative(s) or by representatives from other companies hired by Peerless Mfg. Co. to perform a specific task. This service does not include the supply of any parts. It is performed only on the basis of a bona fide purchase order for field service issued by the ultimate customer or his authorized representative, covering the specific type of service desired. Peerless Mfg. Co.'s service is subject to the Field Service Terms & Conditions shown on the following page.

Service Category	Type of Service	Daily Rates (8 hours)
A	Maintenance Service	$1500.00 plus expenses
B	Startup Service	$1500.00 plus expenses
C	Classroom Instruction	$1500.00 plus expenses
D	Engineering Consultation	Consult PMC-Dallas
E	Annual Equipment Inspection	$1200.00 plus expenses
F	Construction Supervision	$1800.00 plus expenses
G	PLC-Commissioning / Programming	$1800.00 plus expenses

Billing will be based on rates in effect at the time service is rendered. Rates apply within the continental United States only.

Notes:
A) "Time" is based on travel time to the job from the man's regularly assigned office location, on-the-job work hours and return travel to the office location. Travel time will be billed as straight time and will not exceed 8 hours. Travel time from job to job will be a prorated charge.

B) "Overtime" applies to all time spent working in excess of 8 hours during a normal working day, any time other than a normal day shift and any time on Saturdays. Overtime will be billed at 1-1/2 times the regular rate. Time on Sundays and holidays recognized by Peerless Mfg. Co. will be billed at 2 times the regular rate.

C) A "man day" is considered as 8 hours time per man during a normal day shift working hours. The minimum amount invoiced shall be for one man day (or eight hours).

D) "Standby time" is chargeable on-call time during which the service representative is available but unable to proceed with work functions due to jobsite delays. On-site standby time is chargeable at the applicable rate. Off-site standby time is chargeable at full applicable rate. While off-site time on weekdays, beyond 8 hours or weekends and holidays is considered non-chargeable personnel time, the field representative can be made available on an "on-call" basis, if required. This availability, when requested, becomes chargeable at applicable straight time rates. On-site time required becomes chargeable at the applicable overtime rate.

E) Peerless Mfg. Co. does not guarantee that the customer's personnel who participate in instruction sessions are sufficiently trained to properly operate the equipment.

F) For service visits which extend beyond two weeks, the service representative will be allowed to travel home on the second weekend with time and expenses chargeable at the applicable rate.

G) When Peerless Mfg. Co. finds it necessary to hire service representatives from other companies to place major equipment for service, we shall invoice for this service at cost, plus 10% to cover handling charges.

H) Field Service may be obtained by contacting Peerless Mfg. Co., SCR Systems Division, Dallas, Texas.

I) Two weeks' advance written notice, including a purchase order referencing this document, is required to guarantee that a site representative will be dispatched to the job site. A US$3,000.00 cancellation fee will apply if the site visit is canceled within three (3) working days of departure.

J) A minimum notice of 72 hours is required on all cancelations.

Expenses:
A) Travel – Round trip plane tickets, private or rental automobile charges from the point of regularly assigned location of the service representative plus any required local travel. Private automobile charges will be 60 cents per mile. Tolls and parking fees are additional. When our service representative goes from job to job rather than returning to his corporate office, travel charges will be distributed on a prorated basis.

B) Living – Lodging, meals, and incidental costs are living expenses.

C) Receipts for air travel, automobile rental and lodging will be available upon request. Receipts for meals and incidental costs are not required by Peerless Mfg. Co., but will be supplied upon prior arrangements.

D) Special Equipment – If necessary for start-up or is requested by the customer, Peerless Mfg. Co. will furnish any special equipment:
- Portable emissions analyzer – charged at $75.00 per hour
- Rented equipment – charged at rental cost plus 10% administration fee.

E) 10% administration fee will be applied to all expenses.

XII. PEERLESS MFG. CO. FIELD SERVICE TERMS & CONDITIONS:

The following Terms & Conditions of Sale shall govern all orders and take precedence when Terms & Conditions Between Peerless Mfg. Co. and the Customer differ in substance and/or are in conflict.

General Conditions:
Peerless is not responsible for the performance of equipment when startup and adjustment is performed by persons who are not Peerless Mfg. Co. Field Authorized Service Representatives. Satisfactory equipment operation is dependent upon proper ammonia, air and/or temperature control; limit devices; operating permissiveness; and sound operating practices.

In view of the nature of application and frequent interrelatedness of Peerless Mfg. Co.'s equipment with that of other companies' equipment, minor resizing of critical parts may become desirable and necessary at startup or during early operation in order to improve the application. Any such changes shall not affect nor change normal warranty or liability or validity of the customer's purchase order(s) for equipment or services. Any parts required for such modifications are considered a no-charge warranty replacement. However, additional startup service required to make such minor changes at time of startup (e.g. flow meters, spray nozzles, to optimize system operation) is not covered by warranty and is chargeable to the customer. All necessary parts will be supplied on a no charge warranty basis. However, Peerless Mfg. Co.'s service labor will be invoiced separately.

Peerless Mfg. Co. maintains the following insurance coverage: Commercial General Liability, Foreign Worldwide Liability, and Employers' Liability and Business Automobile liability. A Statutory Insurance Certificates is available upon request. Customers who order service without a purchase order will be charged a $75.00 administrative fee to be named as an additional insured.

Specific Term:

1. Pricing
Purchase orders are subject to review and acceptance by Peerless Mfg.

2. Terms of Payment
Invoices are to be in cash, net 15 days from invoice date. All overdue accounts will be subject to a late charge of 1.5% per month from due date until paid. Peerless Mfg. Co. does not hereby agree to give further time for payment, but rather intends to impose a charge for late payment. Peerless Mfg. Co. hereby reserves any right it may have to file a mechanic's lien against the site at which Peerless Mfg. Co. performs service.

3. Limitations of Liability
Peerless Mfg. Co. shall not be responsible for the acts and workmanship of the employees, contractors, sub-contractors or agents of the Customer. Peerless Mfg. Co. shall not be liable to the Customer for any loss or injury to persons or property caused by negligence of the Customer, its employees, contractors, suppliers or their employees, agents or sub-contractors. In no event shall Peerless Mfg. Co. be liable, whether arising under contracts, tort (including strict liability and negligence) or otherwise, for loss of anticipated profits, loss by reason of plant shutdown, non-operation or increased expense of operation, service and erection, cost of purchase of replacement power, or for any special, indirect, incidental or consequential loss or damage of any nature arising at time or from any cause whatsoever.

4. Indemnification
Peerless Mfg. Co. will defend and indemnify the customer against all damages, liability, claims, losses and expenses (including attorneys' fees) for injury or death to persons or damage to property of other arising out of, or resulting in any way from any defect in the services purchased hereunder or from any negligent act or omission of them, its agents, employees or subcontractors, provided a request is made within 90 days after the services are rendered. In that event, Peerless Mfg. Co. will not be liable for bodily injury or property damage beyond $1,000,000 per occurrence and in the aggregate.

5. Arbitration
In the event any dispute arises out of or relating to this Agreement, the parties shall attempt to resolve their differences by negotiation failing which either party may submit the matter to arbitration. The arbitration shall be conducted in accordance with the Commercial Rules of the American Arbitration Association and judgment on the award may be entered in any court having jurisdiction. There shall be one arbitrator, to be selected by mutual agreement of the parties. If the parties cannot agree on such arbitrator within thirty days after commencement of discussions regarding such arbitrator, then either party, on behalf of both may request appointment of the arbitrator by the then presiding judge of the Federal District Court for the State of Texas. Each party shall pay the fees of its own attorneys, and the expenses of its witnesses and all other expenses connected with presenting its case. Other costs of the arbitration, including the costs of any record or transcription of the arbitration, administrative fees and the fee of the arbitrator shall be borne equally by the parties.

QUOTATION
an ISO 9001 Company
1675 Glen Ellyn Road - Glendale Heights, IL 60139
Phone: 630-858-2600 - Fax: 630-858-7172
e-Mail: cbc@fan.net
All purchase orders are subject to acceptance
by Chicago Blower Corporation at its home office

3/11/2013

Represented by:
BAGWELL ASSOCIATES, INC.
4853 S. Sheridan
Tulsa, OK 74145-5760
918/749-1601/ Fx: 3370
e-mail: bagwell@intcon.net

Allen Burris
Tulsa Heaters Inc.
1350 S. Boulder #800
Tulsa, OK 74119

Ref: Your#P13-8431
Our BAC-191-13

	OEM Price Each	Wt. Each
ID FAN (VFD): Size 54 DIDW, RPM 1200, BHP 148, Arr. 7		18,500 #

Selection, details, features, comments and exceptions to specs are on pages 2 through 5 and are a part of this quotation.

Shipment: 18-19 weeks after receipt of order with waiver of drawing approval for fan.

Drawings: Currently drawing time is 3-4 weeks

F.O.B.: Glendale Heights, IL, freight collect or 3rd party billing. Ship direct items are FOB Factory, point of origin, and ship collect or 3rd party billing.

Terms: Net 30 and subject to conditions of sale on reverse side. Quotation is effective for 30 days.

Thank you for this inquiry. We hope you are successful in your proposal and that we, in turn, receive your order for the fans. If so, please make it to CHICAGO BLOWER CORP., in care of us. Because of the dollar value of this order, we would need a signed purchase order for Chicago Blower to enter the order.

Tom Van Eman
cc: Mr. Joe Carden - Chicago Blower Corp.

All sales will be made exclusively upon the terms and conditions shown on the reverse side. Provisions in Customer's purchase order which are contrary or additional are not binding upon Chicago Blower unless accepted in writing.
PLEASE ISSUE PURCHASE ORDER TO: CHICAGO BLOWER CORP. C/O BAGWELL ASSOCIATES, INC AND FORWARD TO THE ADDRESS ABOVE.

INDUCED DRAFT FAN-VFD Control - DIDW

Fan Selection: 5414 D/1903 Heavy Duty, airfoil blade wheel, Arr. 7S1, with two inlet boxes.

Performance: Test Block

ACFM	OV FPM	SP In. W.C.	RPM	BHP AT DENSITY	LB/CU.FT. DENSITY	^{o}F OPER TEMP	^{o}F MAX TEMP
102000 (242,308 pph)	3441	7.1	1185	148.3	.0396	499	599

Features Included: Flanged inlet and outlet; flanged housing drain with blind cover; raised, bolted, insulated access door in housing and inlet box; split housing 1/4" thick; mfg standard shaft seal; insulation studs; flanged shipping splits; API 560 construction (See Page 8 for details); CBC standard 2 hour witnessed mechanical run test*.

Vibration Inertia Base: Steel channel inertia base with pan and re-bar. Base is designed to isolate the concrete fill from the flanges that will see fan inlet temp. Base is filled with concrete on site (by others) fan is then mounted on the base before being lifted to top of heater. Base sits on 1" deflection springs mounted in space-saving brackets, which mount to your structure. Base is painted to match fan. Fan inlet box flanges are bolted to top of base. Inlet vibration boots will bolt to bottom of inertia base. Bolting not included (long all thread bolts that reach the depth of the base are recommended.) Assembly by others in field. Base ships direct, FOB Factory, freight collect. Mfg. standard warranty. Base may ship in two pieces due to large size and may require field assembly.

Vibration Boots: FlexCom Chemshield material, suitable to 600F, punched to match the fan inlet boxes and outlet flange. Joints are shipped with backing bars of carbon steel, painted to match the fan. Bolting is not included. Boots ship direct from manufacturer, freight collect, and FOB factory. Mfg. standard warranty.

Surface Preparation: Sand blast per SSPC-SP6, with one coat inorganic zinc primer 3 mil, per API-560, plus one coat epoxy on un-insulated parts of the fan.

Materials: A36 Carbon Steel housing. A1011 and A572 Corten wheel. Cast steel hub, shrink fit.

Shaft: 1045 steel, with cooling wheels.

Bearings: Link Belt 6800 Series roller bearings, oil lubricated, with 16 oz. Trico constant level oilers. Pilot drilled for field doweling. Drilled and tapped for vibration sensor stud.

Coupling: Thomas 71 non-lubricated, with spacer. Size 512.

INDUCED DRAFT FAN (Continued)

Guards: Shaft, bearings, coupling, cooling wheel. Extended grease fittings. Non-sparking aluminum.

Vibration Sensor: Metrix model ST5491E 021 020 00 Vibration Transmitter, LCD Indicator, loop powered, 4-20mA output proportional to velocity, interfaces with PLC, DCS and 4-20mA monitors, flying lead connection. Ships loose with fan for protection, and is field mounted by others on installed mounting stud.

Motor: 200 HP; 1200 RPM; 449T Frame; TEFC; 460-3-60 current; 1.15 SF, IEEE841 construction, with 120v space heater with leads to aux J-box. Includes shaft grounding rings to protect the motor from transient voltages created by the drive. TECO-Westinghouse, Max E2-841, model HB2006.

* Fan Run Test in factory may be with factory 900RPM motor. As there are no dampers on this fan, the HP at ambient temps would exceed the job motor capabilities, so the testing will be done at reduced RPM. After the test, the job motor will be installed and aligned. Job motor is tested in the TECO/Westinghouse factory and a run test report of that test will be provided. Test is 2 hours after bearing temps have stabilized. Witnessed.

FAN SPECIAL FEATURES INCLUDED TO MEET API-560

Continuously rising fan curve
100 ^{o}F higher design temp for ID fan
Minimum ¼" housing on ID fan
Split housing
24" x 24" bolted access doors in housing and inlet box
Flanged drain
Blind cover for flanged drain
Minimum thickness of wheel blades
Interference fit hubs
Cast Steel hubs over 300 ^{o}F
Higher than standard critical speed
Mechanical run out check of shaft
Special balance of wheel to level G2.5
Oil lube roller bearings
16 oz. Trico constant level oilers with sight glass on bearings
Cooling wheel on ID fan with guard
Pilot drilling of bearings for field doweling
AWS D14.6 code welding of fan rotor
AWS D1.1 code welding of fan housing and pedestal
All rotor butt welds full penetration
All welds continuous.
A36 housing
Corten wheel
S. S. nameplate
S. S. rotation arrow
Material mill test reports
Spacer coupling
Actuators sized for 60 psi supply
Special paint: Sandblast SP-6, one coat inorganic zinc primer dft, interior and exterior, plus one coat epoxy on exposed (non-insulated) surfaces.

COMMENTS AND EXCEPTIONS TO SPECIFICATIONS

These fans will be designed and constructed in accordance with API-560, Annex E, with the following exceptions:

E.2.2.1	Fan inlet cone is removable in whole with the rotor.
E.2.5.6	Fan shaft for ID fan is mfg standard, and does not include special machining or stress relief.
E.2.5.8	I.D. Fan does not have shaft sleeves.
E.2.7.4	Critical speeds cannot be confirmed by test stand.
E.2.7.5	List of unsuitable speeds is not available since fan is constant speed design and since fan HP is greater than Chicago Blower Corporation VFD.
E.2.7.6	VFD controlled fan is run at constant speed. List of unsuitable speeds is not available.
E.2.9/1	Bearings are anti-friction, not sleeve type. Sleeve bearings could be provided, but as they require water cooling, this is not practical for the fan mounted on top of the heater.
E.3.2.4	ID driver sized for dampered start.
E.3.4.2.4	Dampers are fail open, therefore signal shall be decreasing to open.
E.3.4.2.5	Dampers do not lock in place on loss of motive air, but fail open.
E.3.4.2.7	External damper position shown on actuator positioner.
E.4.1.2-5	Tests not specified or available.
E.4.3.2	See recommended storage procedures attached.
E.4.3.2	Crating per manufacturer's standard for domestic shipment only.
E.5.2.5	Manufacturer's standard data for fans and motors to be supplied. Not all items may be provided.

<u>RECOMMENDATIONS FOR EXTENDED STORAGE OUTDOORS – INSTALLED OR UNINSTALLED</u>

1. ~~A finish coat of paint must be applied prior to storage. Chi-cago Blower Corp. black primer alone is not intended to pro-vide long term protection of the metal surfaces. All gaps created by stitch welds or bolted connectio ns should be caulked.~~ This requirement does not apply to API560 fans with continuous welds and inorganic zinc paint.

2. ~~Inlet and outlet openings should be covered to prevent foreign objects from striking the wheel and collecting in the housing, if they are not already covered. Shrink wrap covering may not be sufficient. Flange covers of wood or steel are recommended, and are available from Chicago Blower Corp. at extra cost if ordered with fan.~~

3. Fan shaft, bearing faces, couplings, motor shafts and other machined surfaces should be kept coated with a heavy rust preventative such as Texaco Compound "L".

4. Thoroughly inspect the fan for any scratches or damage from shipping and handling. Scratches in the paint should be touched up and any removed rust preventative replaced.

5. ~~Lubricate the bearings with premium quality NLGI 2, Lithium Soap Based mineral oil grease upon receipt of the fan. Add enough grease to cause a slight purge at the shaft seals while rotating the shaft. This procedure must be executed twice monthly until the fan is placed into service.~~ If the fan requires oil lubrication instead of grease, fill the lower half of the bearing housing with turbine grade ASTM D-943 oil such as Texaco Regal R&O #68 or #100 or it's equivalent.

6. <u>Rotate the wheel ten full revolutions twice every month</u>. The grease or oil in the bearings may settle exposing the top row of balls or rollers. Regular rotation of the wheel and shaft will keep them coated in lubrication to prevent rust. Use the inspection door for this operation . ***(Note:!! Failure to comply with this requirement may lead to bearing failure at start-up)***

7. The fan cannot be allowed to sit in water or other liquids and should not be exposed to temperatures that exceed 130°F (54 °C) .

8. Contact the motor manufacturer for specific instructions on storing the motor.

9. Cover the entire fan with a tarp to keep dust and dirt from reaching the bearings, coupling, and motor as well as protecting the finish coat of paint. Allow some openings to permit air circulation and prevent a build-up of moisture. If the fan has been installed and is to sit idle for some time, cover the fan shaft, bearings, coupling and motor. It is also recommended that the fan inlet (or silencer inlet) be covered per item 2 above.

(Continued on Page 2)

RECOMMENDATIONS FOR EXTENDED STORAGE OUTDOORS – INSTALLED OR UNINSTALLED

10. Do not store fans in an area of excessive vibration such as a railroad siding or close to any operating machinery which produces vibration. This condition can brinell the bearings.

11. Prior to start-up, remove excess grease or oil from bearings per bearing manufacturer's instructions, or contact the Chicago Blower Corp. service department for additional information and/or instructions.

12. Chicago Blower offers fans Start-Up service and it is highly recommended for fans that have been in extended storage, or have been installed but sitting idle for significant lengths of time. Contact Chicago Blower or your local Chicago Blower representative for details, costs and scheduling.

13. You may contact Chicago Blower Corp. (for start-up service or bearing information) by mail, phone, fax or e-mail. You may find your local area representative by going on-line to www.chicagoblower.com and selecting the "Sales Offices" option.

Chicago Blower Corp.	Ph: (630) 858-2600
1675 Glen Ellyn Road.	Fx: (630) 858-7172
Glendale Heights, Ill 60139	e-mail: fans@chicagoblower.com
(Subject	Line: "Service Dept.")

Pipe spool #2 (Qty 2) will consist of the burner header of a 6" NPS S40 size with a quantity of six (6) 3" NPS S40 individual lines going to a hand valve (with no limit switch), actuated valve (with limit switch), a pressure gauge, and ending at a flex hose.

Pipe spool #3 (Qty 2) will consist of the scanner purge air header of a 1" NPS S80 size with a quantity of six (6) ½" NPS S40 individual lines going to a hand valve (with no limit switch) and tubing ran to a flex hose. There will be a small rotameter for pressure.

System #2

This is a BMS system that will supply a 4 burner heater. The on-skid main line will be 3" CS and the on-skid pilot line will be a ¾" CS. This will possess the double block valves with limits and indication as required by NFPA 87. The pilots will also possess a double block valves with limits and indication. Between the double blocks, a small ½" fail open Asco solenoid will serve as a bleed. There will also be a 1" NPS galvanized CS air line also on-skid to supply air to actuate the on-skid valves.

Please note ICC has not included any ship loose items other than what is listed on the attached BOM.

Per request, ICC will supply as ship loose pipe spools similar to those supplied on the previous THI projects of a straight run with drop-offs evenly spaced.

Pipe spool #1 (Qty 1) will consist of the pilot header of a ¾" NPS S80 with a quantity of four (4) ½" NPS S80 individual lines going to a hand valve (with no limit switches) and an Asco fail closed solenoid to serves as a block valve. Each individual line will end at a flex hose.

Pipe spool #2 (Qty 1) will consist of the burner header of a 3" NPS S40 size with a quantity of four (4) 2" NPS S40 individual lines going to a hand valve (with no limit switch), actuated valve (with limit switch), a pressure gauge, and ending at a flex hose.

Pipe spool #3 (Qty 1) will consist of the scanner purge air header of a 1" NPS S80 size with a quantity of four (4) ½" NPS S40 individual lines going to a hand valve (with no limit switch) and tubing ran to a flex hose. There will be a small rotameter for pressure.

Please note per request, ICC is quoting to a US Class 1 Div 2 specification that will be accomplished through NFPA 70 (NEC).

For the purpose of this quotation, the local control panel for each BMS system will be on-skid rather than off-skid. It can be relocated off-skid in a Field Equipment Room if required and an operator station only remain on-skid – if interested, please contact ICC for a revised quotation.

The on-skid control panel will be purged, IP65 min, NEMA 4X, 304SS. ICC is willing to work with the customer to develop a suitable quotation and system. Please contact ICC if clarifications or a revised price is needed.

ICC's quotation reflects one (1) flame scanner and one (1) flame rod per pilot/burner combination. A UV flame scanner will detected the burner flame and the flame rod will detect the pilot flame. Per request, an option has been supplied for the use of THI supplied John Zink HEV units and redundant flame scanners rather than ionization rods. Please refer to the option section below.

Please also note an email was received requesting to minimize the use of Chinese components. ICC has worked to eliminate Chinese cast alloys from our quotation, which resulted in several vendor differences between the previous projects and this. Please note that Chinese components are the standard for most valve manufacturers and locating other options may result in longer lead times.

Per request, this quotation meets the intent of NFPA 87 with regard to ICC's scope of supply. ICC is a sub-contractor and is only supplying a portion of a larger system. ICC has no direct interaction with the end customer, coordination with them and their documentation control shall be the responsibility of THI.

ICC has assumed a requirement to the intent of SIL-2. Please advise if this needs to be revised, as it may have an impact on pricing. Although, ICC offers this system capable to meet the requirements of SIL 2, please note ICC can only offer SIL compliance in regards to our scope of supply. Any systems not provided by ICC, it is the responsibility of others to ensure conformance to SIL.

The system PLC (logic solver) is an Allen-Bradley Contrologix, which is capable of achieving SIL-2 operation as per IEC 61508. An HMI will be available for on-line monitoring and off-line changes via password protection.

Please note this HMI will be connected to the BMS PLC via Ethernet. All startup/shutdown and maintenance controls will be at this enclosure as well as local monitoring. This HMI installation will be suitable for the Division 2 area.

Please note this quotation assumes all control functions shall be at the DCS level. The PLC accompanying these systems only handles startup and shutdown capabilities with minimal interaction to the control valves, dampers, etc. ICC is not providing any programming or configuration of the DCS system. If a scope change is needed to include control functions, please contact ICC and we can revise the quotation.

Communication protocols available include Ethernet and Allen-Bradley standard protocols. ICC will be providing communication maps for the customer's interface with their DCS system. Customer will need to provide details at time of order in regards to their preferred communication protocol and standards. ICC is only supplying redundancy in regards to the PLC communications, power supplies, and CPUs. There is no I/O redundancy.

All on-skid instrumentation will have electrical connections routed back to the on-skid panel. For this system, ICC will be applying a conduit/wire installation. ICC will use rigid galvanized conduit and THHN/TFFN wire to terminate panel to on-skid instruments.

Additional ship loose panels have also been provided with this quotation that houses the ignition transformers. Please note the enclosures will be 304SS, NEMA 4X, IP65 minimum. Please note that this is typically allowed by NFPA and API as non-hazardous area classification due to close proximity to an open flame. For this quotation, the ignition panels are <u>NOT</u> purged and are for non-hazardous location.

Please review our provided BOM with our suggested manufacturers in case any issues may be determined. ICC has selected good quality materials typically found in industry and easily obtainable.

ICC is providing PLC based automation and not PC based automation. ICC is only supplying a small portion of the overall project. ICC can supply PC based automation if necessary; if interested, please contact ICC with a more detailed scope and ICC can provide a separate quotation.

Any off-skid instrumentation provided by ICC shall be ship loose for field installation.

ICC is not providing any motors, pumps, VFD, SCRs, dampers, tubeskin thermocouples, flame rods, ignitors, or any other component normally supplied by the heater manufacturer. Only items listed on the attached BOM are included. It is still assumed that the site will be supplying their own purge air blower similar to previous projects.

ICC is not providing any UPS or backup power packages.

This quotation includes labor and materials for two (2) BMS systems with ionization monitors for pilots and flame scanners for flame detection. The pilot shall light via spark provided by ignition transformer. In general, the electrical signals shall be predominantly 24VDC and 120VAC, where AC voltage is required. 220VAC can also be supplied.

ICC is not responsible for any utility piping, area lighting, heat tracing, insulation, or fire suppression.

Due to our limited scope of supply, ICC is taking exception to and not providing PHWT & PMI. If required, please contact us and we can revise the quotation. Piping fabrication will be to ASME B31.3 with 5% X-Ray and pneumatic testing at 1.5x working pressure prior to paint.

Please note that ICC is providing the following certifications/conformances.
+ US Class 1 Div 2 Conformance

This quotation does not include any PED certifications. If required, please contact us and we can add this via a revised quotation.

Please note ICC has not included in this proposal any other requirements. ICC may be able to provide conformance to other specifications, i.e. UL/CUL, IEC, ATEX, PED, INMETRO, etc. If interested, please contact us for a revised quotation.

Please review the provided BOM for a full listing of ICC provided components; this shall apply as the governing document to this proposal. ICC reserves the right to swap equipment and manufacturers on an "or equal" basis to resolve issues such as availability or compatibility. If there are any other revisions to the scope, please contact ICC for revised pricing.

ICC is willing to work with the customer and end user on the development of this proposal in terms of operability and to match the requirements. Please contact us for suggestions, revisions to scope and/or materials supply on this quotation. Any additional labor or materials required, not referenced in a quotation provided by ICC shall be on a time/material basis.

ICC has based its costs on current market pricing of materials. These materials are subject to escalation based on changing market conditions. The basis for the escalation shall be the CPI Index values based on date of acceptance of Purchase Order from THI. The costing will be evaluated on a quarterly basis and will be applied to the costs for the following quarter.

Supplied Quote Documentation

ICC has reviewed the documents provided and this quotation meets the intent of them as they apply to our scope. This document stands alone as ICC's scope of supply. Only items contained within the attached BOM are included in this quotation. Any changes to this quotation must be provided in writing and a revised quotation shall address per line item.

Per the latest information received, ICC is to provide a system to the intent of NFPA 87. ICC has also provided a P&ID to be used as a reference to this quotation.

ICC takes exception to any specification not directly supplied to us. If conformance to a specification not listed, please provide and ICC can review and revise scope as necessary.

Please review this quotation carefully and if there are any questions regarding the scope of supply, please contact us.

Purchasing & Misc. Services:

Please refer to attached listing for materials ICC will be purchasing. Manufacturer names are included. This list is provided on an as-equal status and some manufacturers may require crossing over to facilitate materials that are commonly acquired locally for these projects. Any item not on the list accompanying, is not included in this quotation.

Please note the on-skid enclosure has been quoted as 304SS, IP 65 minimum, NEMA 4X, suitable to Class 1 Div 2.

Please note the ship loose ignition panels shall be 304SS, IP 65 minimum, NEMA 4X, unclassified

This quotation does not include any spare parts. ICC has no issues providing spares and/or listing for this, but at this stage, spare parts lists are very pre-mature. After detailed engineering is complete, a recommended spare parts listing with manufacturer and model numbers can be provided with a separate quotation for pricing.

If additional components or a manufacturer revision is required, ICC can provide via a revised quotation.

Fabrication Services:

ICC will provide all labor necessary to construct:

Total of 2 systems consisting of:

System #1 (12-pilot/burner system)
- + (Qty 1) Structural Skid, I-Beam & C-Channel base
- + Fuel Trains
  - + (Qty 1) NPS 6" Burner Pipe Train, Carbon Steel
  - + (Qty 1) NPS 1" Pilot Gas Train, Carbon Steel
  - + (Qty 1) NPS 1" Instrument Air Supply Line, galvanized w/ CS valves
- + (Qty 1) Control Panel (On-skid installation)

+ Conduit/Wire between on-skid devices and control panel
  + US Class 1 Div 2 installation
  + ICC uses only copper wire
  + Rigid Galvanized Conduit w/ THHN/TFFN Wire
+ (Qty 2) Ignition Panel (Ship Loose for field/remote Installation)

System #2 (4-pilot/burner system)

+ (Qty 1) Structural Skid, I-Beam & C-Channel base
+ Fuel Trains
  + (Qty 1) NPS 3" Burner Pipe Train, Carbon Steel
  + (Qty 1) NPS 3/4" Pilot Gas Train, Carbon Steel
  + (Qty 1) NPS 1" Instrument Air Supply Line, galvanized w/ CS valves
+ (Qty 1) Control Panel (On-skid installation)
+ Conduit/Wire between on-skid devices and control panel
  + US Class 1 Div 2 installation
  + ICC uses only copper wire
  + Rigid Galvanized Conduit w/ THHN/TFFN Wire
+ (Qty 1) Ignition Panel (Ship Loose for field/remote Installation)

Please note ICC's skid is for the support of the fuel trains and the control panel only. Only identified items shall be located at the skid.

All identified on-skid instrumentation shall be pre-wired and routed to the skid-edge enclosure. ICC uses standard grounding connections at two (2) locations near skid edge (one at corner nearest to enclosures and the other diagonally opposite).

Painting for carbon steel lines and skid shall be a standard 3-coat system with a sandblast to SSPC-SP10. ICC does not paint galvanized or SS components/lines. ICC does not paint over manufacturer's standard paint for instrumentation and valves.

Additional fabrication services required shall be at additional cost & provided in a separate quotation. Any changes to scope specified here shall incur additional charges. Please refer to attached listing.

Engineering:

Engineering services provided within this quotation are as follows:

+ Material selection & engineering design
+ ISA Datasheet Format S20
  + Vendor Supplied Data
+ BMS PLC Programming
+ BMS HMI Programming
  + Screens include:
    + Skid Overview and Status
    + Heater Overview and Status
    + Alarm screen w/ 1st out indication
      + Note logging functions by others if required (recommended to be via DCS)
    + Transmitter details & setpoint adjustment
      + Monitoring only for normal use
      + Adjustment allowed via password and in maintenance mode
+ Operational Philosophy (Narrative style)
+ Cause/Effect Diagrams

+ ICC standard acceptance testing (FAT)
  + 100% continuity test
  + Material conformity
  + Functional Test and walkthrough with customer
    + Confidence test - demonstration of normal startup and shutdown
    + Event test - demonstration that shutdowns will take system into safe state

Per ICC's quality assurance program, ICC will retain control of all documentation produced by ICC until the final documentation is submitted. Documents will be provided in Adobe .PDF format for approval. The final data packet will possess a CD with the files in their native format (i.e. AutoCAD, MS Excel, MS Word, etc.)

A point that may be discussed ARO is a separate screen for control loop information (if data available from DCS). This will be monitoring only with no interaction from the BMS system. Only information from the DCS (as carried on communications) can be available. This can be added on a time/material basis dependant upon how much information (if any) the customer would like to display. No control is permitted from the PLC.

Workstations are not included in this quotation. If required, several factors will need to be discussed. ICC can provide via a revised quotation.

Although ICC is providing programs, ICC has not included in this proposal software. If the end user requests, ICC can work with them to assist in purchasing a copy for their use - the software will need to be registered to a responsible party at the end user's location.

Please note that we are only responsible for ISA datasheets for items purchased by ICC. These datasheets will be provided via both hardcopy and in MS Excel format.

ICC is providing project management at ICC level only. Any project management of the overall system, installation, or involving end user is by others.

Please note that no meeting times or field visits have been included in this quotation. If required, they will be provided on a time/material basis at ICC standard rates. The customer and/or their inspectors shall have access to ICC's facility M-F, 8am-5pm CST. Please call ahead of time to ensure someone will be present to meet with them. If the end user or a 3rd party inspector visit is required, it is THI's responsibility to provide a representative on-site to meet with them.

ICC is providing acceptance testing (FAT) at ICC's facility in Tulsa, OK. ICC is not providing any SAT or field work with this quotation. If required, ICC can provide on a time/material basis per our standard rate sheet or via a separate quotation. Customer attendance of the FAT or written waiver of attendance must be provided. For the purposes of this quotation, the customer is THI. It is THI's responsibility to coordinate with their customer.

The standard factory acceptance test will be scheduled to coincide with completion of the project. The customer will be notified 2 weeks beforehand and a mutually suitable time will be agreed upon. Two days should be scheduled for a complete system walkthrough. Some testing will be done prior to customer's arrival and a review of all testing and results shall be included. ICC would recommend performing the testing on multiple systems at the same time.

Further engineering services required shall be at additional cost & provided in a separate quotation or via time/material basis at ICC standard rate sheet. Any changes to scope specified here shall incur additional charges.

Drafting:

Drafting services provided within this quotation are as follows:
+ P&ID (est. 1 page)
+ Electrical Schematics (est. 8-10 pages)
+ Layout Drawings (est. 3-5 pages)
+ Skid General Arrangements (est. 1 page)

Please note page estimates are for each system

Per ICC's quality assurance program, ICC will retain control of all documentation produced by ICC until the final documentation is submitted. Documents will be provided in Adobe .PDF format for approval. The final data packet will possess a CD with the files in their native format (i.e. AutoCAD, MS Excel, MS Word, etc.)

All drawings shall be provided in AutoCAD format at the completion of the project. The customer shall provide any requirements for titleblocks at time of order to avoid additional charges. This quotation only reflects Rev 0 documentation. Any customer changes are to be provided in writing and are subject to cost additions on a time and material basis.

Further drafting services required shall be at additional cost & provided in a separate quotation or on a time/material basis via ICC's standard rate sheet. Any changes to scope specified here shall incur additional charges.

Field Support:

No field support or supervision is provided within this quotation. This may be provided at additional cost & provided in a separate quotation. Please contact us one (1) month in advance for scheduling and rates. Field Support is available through our sister company, Martin Consulting Group, Inc.

Please note there is no SAT associated with this quotation. This is one of the many services available via time/material basis or separate quotation.

Deliverables:

The following shall be considered a list of documentation deliverables included in this quotation:

Each system will have a separate package that consists of the following:

Hardcopy:
+ ISA Datasheets Format S20 (8½ x 11)
  + Standard vendor catalog cut sheet information
+ ICC standard acceptance test (8½ x 11)
  + Test results, design data, additional records
+ P&ID (11 x 17)
+ Electrical Schematics (11 x 17)
+ Layout Drawings (11 x 17)
+ Skid General Arrangements (11 x 17)
+ Cause/Effect Diagrams
+ BMS PLC Program

+ Operational Philosophy Narrative w/ HMI screenshots

Softcopy (via CD)

+ ISA Datasheets Format S20 (Excel/Adobe format)
+ P&ID (AutoCAD format)
+ Electrical Schematics (AutoCAD format)
+ Layout Drawings (AutoCAD format)
+ Skid General Arrangements (AutoCAD format)
+ Cause/Effect Diagrams (MS Excel format)
+ PLC Program
+ HMI Program
+ Operational Philosophy

ICC is providing our documentation in English only. If any translation to another language is required, this shall be by others.

Pricing:

All unpaid invoices will be billed with a late fee at 1.5% monthly and are due on a NET 15 day basis.

Burner Piping Notes:

It was requested to include burner piping similar to what was provided on the previous THI projects. The previous projects were straight line runs of burner piping. It appears this new quotation is in a circle/ ring formation. Please note this is not how the burner pricing has been estimated, some cost adders may be needed.

HEV Option Notes:

It was requested to provide an option for

+ At the individual ignition panels the removal of the ignition transformers
+ At the individual ignition panels the removal of the ionization relays
+ At the individual ignition panels the addition of the THI supplied HEV units
+ Additional ship loose UV flame scanners for each pilot flame
+ Programming to accommodate a 2oo2 configuration with pilot and burner flame scanners

International Custom Controls
7835 S. 87th W. Ave, Tulsa, OK 74131, Phone: 918.216.2000, Fax: 918.216.2009

The HEV units will be equal to or similar to the John Zink style previously discussed. They will be purchased by THI and free-issued to ICC for installation into the individual ignition panels. Please note with a 2oo2 configuration on pilot/burner flames, once the main burner is lit, the pilot scanner can no longer determine the pilot flame vs the burner flame. With the scanners, a 1oo2 detection will generate an alarm and loss of both flames 2oo2 is needed to shut down. If a different protection scheme is needed, please contact us and we can discuss.

Schedule:

Upon receipt of purchase order, Rev 0 documentation package shall be provided within 2-3 weeks -- this consists of the P&ID, ISA datasheets, panel layout drawings, and cause/effect diagrams all similar to the previous THI projects. Upon customer's written approval of datasheets, all items will be placed on order or the first revision will be made and changes in pricing generated. After approval of Rev 0 documentation package, subsequent documentation will be generated. Expected material delivery time is 8-10 weeks with the long lead items being 12-14 weeks. Fabrication will begin as materials arrive. Expected completion to be approximately 2-3 weeks after receipt of all materials based upon progressive delivery times. The checkout of all systems shall be scheduled to coincide with the final completion of system. All fabrication shall be performed at ICC shop.

This quotation is for Ex-Works, packaging & shipping to be handled by others.

We trust this will meet your needs and look forward to starting the project shortly.

Best Regards,
International Custom Controls, L.L.C.

Brian Reynolds

Attachment #1 – Preliminary BOM
Please note these are ICC standard manufacturers and these are provided on an "or equal" basis
+ Specific manufacturers and model numbers to be identified during engineering phase

Tag	Size	Description	Manufacturer	Qty
		FG Line (On-Skid)		1
	6"	Hand Valve, Gate, CS Body, 150#RF	Velan or Eq	1
	6"	Strainer, CS Body, Std Mesh, 150#RF		1
	1/2"	Drain Valve, Gate, CS Body, NPT	Velan or Eq	1
	4"	Regulator, CS Body, 150# RF	Fisher or Eq	1
	1/2"	Drain Valve, Gate, CS Body, NPT	Velan or Eq	1
		Pressure Gauge, Plastic Body, SS Internal	Wika	1
	1/2"	Block Valve w/ Bleed screw, CS Body, NPT	PGI/Agco	1
	1/2"	Limiter		1
		Pressure Transmitter	Honeywell/Rosemount	1
	1/2"	Block Valve w/ bleed screw, CS Body, NPT	PGI/Agco	1
	1/2"	Limiter		1
	6"	Hand Valve, Gate, CS Body, 150# RF	Velan or Eq	2
		Control Valve, VBall, CS Body, 150# RF w/ actuator, I/P, solenoid	Fisher or Eq	1
	1/2"	Hand Valve, Gate, CS Body, NPT (Drain)	Velan or Eq	2
	2"	Hand Valve, Gate, CS Body, 150# RF	Velan or Eq	2
		Bypass Regulator, CS Body, 150# RF	Fisher or Eq	1
	1/2"	Hand Valve, Gate, CS Body, NPT (Drain)	Velan or Eq	2
		Pressure Gauge, Plastic Body, SS Internal	Wika	1
	1/2"	Block Valve w/ Bleed screw, CS Body, NPT	PGI/Agco	1
	1/2"	Limiter		1
	6"	Actuated Valve, CS Body, 150# RF FC Actuator, Limit Switches, Solenoid	Jamesbury or Eq	2
		Pressure Gauge, Plastic Body, SS Internal	Wika	1
	1/2"	Block Valve w/ Bleed screw, CS Body, NPT	PGI/Agco	1
	1/2"	Limiter		1
	1/2"	Hand Valve, Gate, CS Body, NPT	Velan or Eq	1
	1/2"	Solenoid, Fail Open, NPT	Asco or Eq	1
		Pressure Gauge, Plastic Body, SS Internal	Wika	1
	1/2"	Block Valve w/ Bleed screw, CS Body, NPT	PGI/Agco	1
	1/2"	Limiter		1

Tag	Size	Description	Manufacturer	Qty
		Pressure Transmitter	Honeywell/Rosemount	1
	1/2"	Block Valve w/ bleed screw, CS Body, NPT		1
	1/2"	Limiter		1
	1/2"	Drain Valve, Gate, CS Body, NPT	Velan or Eq	2
		PG Lines (On-Skid)		1
	3/4"	Hand Valve, Ball, CS Body, SS Ball, NPT	Jamesbury or Eq	1
	3/4"	Pressure Regulator, CS Body, NPT	Belgas or Eq	1
		Pressure Gauge, Plastic Case, SS Internal	Wika/Ashcroft	1
	1/2"	Block Valve w/ bleed screw, CS Body, NPT		1
	1/2"	Limiter		1
	3/4"	Actuated Valve, CS Body, NPT FC Actuator, Limit Switches	Jamesbury or Eq	2
		Pressure Gauge, Plastic Case, SS Internal	Wika/Ashcroft	1
	1/2"	Block Valve w/ bleed screw, CS Body, NPT		1
	1/2"	Limiter		1
	1/2"	Hand Valve, Gate, CS Body, NPT	Velan or Eq	1
	1/2"	Solenoid, Fail Open, NPT	Asco or Eq	1
		Pressure Gauge, Plastic Case, SS Internal	Wika/Ashcroft	1
	1/2"	Block Valve w/ bleed screw, CS Body, NPT		1
	1/2"	Limiter		1
		Pressure Transmitter	Honeywell/Rosemount	1
	1/2"	Block Valve w/ bleed screw, CS Body, NPT		1
	1/2"	Limiter		1
	1/2"	Drain Valve, Gate, CS Body, NPT	Velan or Eq	2
		1" Instrument Air (On-Skid) Galvanized CS		1
	1"	Hand Valve, Ball, CS Body, NPT	Apollo or Eq	1
	1/2"	Hand Valve, Ball, CS Body, NPT	Apollo or Eq	10
	3/4"	Pressure Regulator, CS Body, NPT	Belgas or Eq	1
		Pressure Gauge, Plastic Body, SS Internal	Wika	1
	1/2"	Block/Bleed Valve, CS Body, NPT	PGI/Agco	1

Tag	Size	Description	Manufacturer	Qty
		Process Instrumentation (Ship Loose)		1
		None		
		Burner Piping Instrumentation (Ship Loose)		1
		Burner Piping Instrumentation		
	3"	Hand Valve, Gate, CS Body, 150# RF		12
	3"	Actuated Valve, CS Body, 150# RF FC Actuator, Limit Switches, Solenoid	Jamesbury or Eq	12
		Pressure Gauge, Plastic Body, SS Internal	Wika	12
	1/2"	Block/Bleed Valve, CS Body, NPT	PGI/Agco	12
	1/2"	Limiter		12
		Pilot Piping Instrumentation		
	1/2"	Hand Valve, Ball, CS Body, SS Ball, NPT		12
	1/2"	Solenoids, Fail Closed		12
		Scanner Purge Air Instrumentation		
	1/2"	Hand Valve, Ball, CS Body, SS Ball, NPT		12
	1/2"	Rotameters		12
		Heater Instrumentation (Ship Loose)		1
		Flame Scanners - one per burner	Fireye	12
		Control Panel (Ship Loose)		1
		Enclosure, NEMA 4X, 304SS	Hoffman	1
		Backpan, CS	Hoffman	1
		Labor	ICC	
		Tags	ICC	
		Terminal Blocks & Accessories	Allen-Bradley	
		HMI		1
		ESD Mushroom Pushbutton		1
		Selector		1
		Pushbuttons		3
		Pilot Lights		12
		PLC, Contrologix	Allen-Bradley	1

Tag	Size	Description	Manufacturer	Qty
		Power Supply, 24 VDC		2
		Control Relays	Allen-Bradley	10
		Interposing Relays	Allen-Bradley	32
		Watchdog Timer	Allen-Bradley	1
		Panel Interior Light		1
		Circuit Breakers		7
		Purge System w/ Vent		1
		Ignition Panel (Ship Loose)		2
		Enclosure - NEMA 4X, 304SS	Hoffman	1
		Backpan - CS	Hoffman	1
		Labor		
		Tags	ICC	
		Terminal Blocks & Accessories	Allen-Bradley	
		Ionization Monitors		6
		Ignition Transformers	Dongan	6
		Ignition cable		200

System #2 (4-Burner System)

Tag	Size	Description	Manufacturer	Qty
		3" FG Line (On-Skid)		1
	3"	Hand Valve, Gate, CS Body, 150#RF	Velan or Eq	1
	3"	Strainer, CS Body, Std Mesh, 150#RF		1
	1/2"	Drain Valve, Gate, CS Body, NPT	Velan or Eq	1
		Regulator, CS Body, 150# RF	Fisher or Eq	1
	1/2"	Drain Valve, Gate, CS Body, NPT	Velan or Eq	1
		Pressure Gauge, Plastic Body, SS Internal	Wika	1
	1/2"	Block Valve w/ Bleed screw, CS Body, NPT	PGI/Agco	1
	1/2"	Limiter		1
		Pressure Transmitter	Honeywell/Rosemount	1
	1/2"	Block Valve w/ bleed screw, CS Body, NPT	PGI/Agco	1
	1/2"	Limiter		1
	3"	Hand Valve, Gate, CS Body, 150# RF	Velan or Eq	2
		Control Valve, VBall, CS Body, 150# RF w/ actuator, I/P, solenoid	Fisher or Eq	1
	1/2"	Hand Valve, Gate, CS Body, NPT (Drain)	Velan or Eq	2
	1"	Hand Valve, Gate, CS Body, NPT	Velan or Eq	2
		Bypass Regulator, CS Body, NPT	Fisher or Eq	1
	1/2"	Hand Valve, Gate, CS Body, NPT (Drain)	Velan or Eq	2
		Pressure Gauge, Plastic Body, SS Internal	Wika	1
	1/2"	Block Valve w/ Bleed screw, CS Body, NPT	PGI/Agco	1
	1/2"	Limiter		1
	3"	Actuated Valve, CS Body, 150# RF FC Actuator, Limit Switches, Solenoid	Jamesbury or Eq	2
		Pressure Gauge, Plastic Body, SS Internal	Wika	1
	1/2"	Block Valve w/ Bleed screw, CS Body, NPT	PGI/Agco	1
	1/2"	Limiter		1
	1/2"	Hand Valve, Gate, CS Body, NPT	Velan or Eq	1
	1/2"	Solenoid, Fail Open, NPT	Asco or Eq	1
		Pressure Gauge, Plastic Body, SS Internal	Wika	1
	1/2"	Block Valve w/ Bleed screw, CS Body, NPT	PGI/Agco	1
	1/2"	Limiter		1

Tag	Size	Description	Manufacturer	Qty
		Pressure Transmitter	Honeywell/Rosemount	1
	1/2"	Block Valve w/ bleed screw, CS Body, NPT		1
	1/2"	Limiter		1
	1/2"	Drain Valve, Gate, CS Body, NPT	Velan or Eq	2
		3/4" PG Lines (On-Skid)		1
	3/4"	Hand Valve, Ball, CS Body, SS Ball, NPT	Jamesbury or Eq	1
	3/4"	Pressure Regulator, CS Body, NPT	Belgas or Eq	1
		Pressure Gauge, Plastic Case, SS Internal	Wika/Ashcroft	1
	1/2"	Block Valve w/ bleed screw, CS Body, NPT		1
	1/2"	Limiter		1
	3/4"	Actuated Valve, CS Body, NPT FC Actuator, Limit Switches	Jamesbury or Eq	2
		Pressure Gauge, Plastic Case, SS Internal	Wika/Ashcroft	1
	1/2"	Block Valve w/ bleed screw, CS Body, NPT		1
	1/2"	Limiter		1
	1/2"	Hand Valve, Gate, CS Body, NPT	Velan or Eq	1
	1/2"	Solenoid, Fail Open, NPT	Asco or Eq	1
		Pressure Gauge, Plastic Case, SS Internal	Wika/Ashcroft	1
	1/2"	Block Valve w/ bleed screw, CS Body, NPT		1
	1/2"	Limiter		1
		Pressure Transmitter	Honeywell/Rosemount	1
	1/2"	Block Valve w/ bleed screw, CS Body, NPT		1
	1/2"	Limiter		1
	1/2"	Drain Valve, Gate, CS Body, NPT	Velan or Eq	2
		3/4" Instrument Air (On-Skid) Galvanized CS		1
	1"	Hand Valve, Ball, CS Body, NPT	Apollo or Eq	1
	1/2"	Hand Valve, Ball, CS Body, NPT	Apollo or Eq	10
	3/4"	Pressure Regulator, CS Body, NPT	Belgas or Eq	1
		Pressure Gauge, Plastic Body, SS Internal	Wika	1
	1/2"	Block Valve w/ bleed screw, CS Body, NPT	PGI/Agco	1

Tag	Size	Description	Manufacturer	Qty
		Process Instrumentation (Ship Loose)		1
		None		
		Burner Piping Instrumentation (Ship Loose)		1
		Burner Piping Instrumentation		
	2"	Hand Valve, Gate, CS Body, 150# RF		4
	2"	Actuated Valve, CS Body, 150# RF	Jamesbury or Eq	4
		FC Actuator, Limit Switches, Solenoid		
		Pressure Gauge, Plastic Body, SS Internal	Wika	4
	1/2"	Block/Bleed Valve, CS Body, NPT	PGI/Agco	4
	1/2"	Limiter		4
		Pilot Piping Instrumentation		
	1/2"	Hand Valve, Ball, CS Body, SS Ball, NPT		4
	1/2"	Solenoids, Fail Closed		4
		Scanner Purge Air Instrumentation		
	1/2"	Hand Valve, Ball, CS Body, SS Ball, NPT		4
	1/2"	Rotameters		4
		Heater Instrumentation (Ship Loose)		1
		Flame Scanners - one per burner	Fireye	4
		Control Panel (Ship Loose)		1
		Enclosure, NEMA 4X, 304SS	Hoffman	1
		Backpan, CS	Hoffman	1
		Labor	ICC	
		Tags	ICC	
		Terminal Blocks & Accessories	Allen-Bradley	
		HMI		1
		ESD Mushroom Pushbutton		1
		Selector		1
		Pushbuttons		3
		Pilot Lights		12
		PLC, Contrologix	Allen-Bradley	1

Tag	Size	Description	Manufacturer	Qty
		Power Supply, 24 VDC		2
		Control Relays	Allen-Bradley	4
		Interposing Relays	Allen-Bradley	32
		Watchdog Timer	Allen-Bradley	1
		Panel Interior Light		1
		Circuit Breakers		7
		Purge System w/ Vent		1
		Ignition Panel (Ship Loose)		1
		Enclosure - NEMA 4X, 304SS	Hoffman	1
		Backpan - CS	Hoffman	1
		Labor		
		Tags	ICC	
		Terminal Blocks & Accessories	Allen-Bradley	
		Ionization Monitors		4
		Ignition Transformers	Dongan	4
		Ignition cable		200

ENCLOSURE 1

C1498-M0013

VENDOR TO COMPLETE THIS FORM AND SUBMIT AS AN ATTACHMENT TO VENDOR'S PROPOSAL

IMPORTANT: FAILURE TO INCULDE THIS COMPLETED FORM MANY RENDER QUOTE INELIGIBLE FOR EVALUATION.

1. Your Company Name: Tulsa Heaters, Inc.
2. Sales Representative: Allen D. Burris
3. Telephone: 918 582 9918 Fax: 918 582 9916 Email: allenburris@tulsaheaters.com
4. Manufacturer: Fired Heaters
5. Minority Business or Woman Owned/Operated Enterprise? ( ) Yes (x) No
6. Any Order resulting from this Request for Quotation (RFQ) should be addressed to:

   PAYEE NAME: Tulsa Heaters Inc (Name of Company Submitting invoice) PAYEE PHONE: 918 582 9918

   PAYEE ADDRESS: International Plaza, 1350 S. Boulder Ave, Ste 800, Tulsa, OK 74119
7. Quotation Number: P13-8431 Quotation Date: 11-March-2013
8. INCO Shipping Terms: Ex Works - Loaded Bid Validity: 30 days
9. Terms of Payment: progress payments - net 30 days
10. LEAD TIMES:

Number of Weeks required for Vendor to Enter PO with Factory:		Ø WKS ARO
Number of Weeks After Receipt of PO to Submit Approval Drawings:		6 WKS ARO
Number of Weeks Allowed for S&B Approval of Drawings:		2 WKS
Number of Weeks to Submit Certified Drawing:	____ WKS ARO	3 WKS ARAD
Number of Weeks to Receive Major Materials:	____ WKS ARO	6 WKS ARAD
Number of Weeks to Fabrication/Assembly After Receipt of Major Materials:		____ WKS
Total Number of Weeks for Shipment:	____ WKS ARO	42 WKS ARAD

11. Equipment Cost: 5,867,115 USD
12. Freight: ____ ( ) ACTUAL (x) ESTIMATED Estimated Weight 817,000 lb
13. Total Quote(Less Taxes): 5,867,115 USD (MUST BE FILLED OUT)
14. Quote is in Exact Accordance with S&B RFQ and all Attachments: (x) YES ( ) NO *
15. Quotation Contains Alternate Proposal(s): ( ) YES (x) NO
16. Vendor has agreed to Accept the Enclosed Terms and Conditions: (x) YES ( ) NO *
    (Any exceptions MUST be included. Submitting Vendor's Terms and Conditions is NOT ACCEPTABLE).
17. Vendor has received ALL Data Sheets, Drawings, Specifications, Other Attachments and VIRF as listed in the S&B RFQ: (x) YES ( ) NO

    ____

    (If NO,List the documentation that is missing)
18. Vendor Signature: [signature] Title: Design/Sales Engineer

Furnishing a Total Cost here DOES NOT Eliminate our Requirement for you to Furnish a UNIT PRICE elsewhere in the Quotation for EACH TAGGED or LINE ITEM if more than one piece of Equipment is involved. Do not refer to your proposal for the Total Quote.

* with exceptions/clarifications noted in Proposal.

S & B Engineers and Constructors, Ltd.

SPECIFICATION SHEET

"Thermal Oxidizer Package"

Job No.	C-1469			Item No.	100-SK25.002
P.O. No.				Inq. No.	
By	RAP	Date	11/3/2011	Rev.	B2

CLIENT	Lone Star NGL	SERVICE	Thermal Oxidizer	No. REQUIRED	1
LOCATION	Mont Belvieu, TX	MANUFACTURER			

Process Requirements

B2 - Thermal oxidizer is required to destroy hydrocarbons contained in off gas vents from an amine treatment/regeneration package (DEA) and misc process vents.

- Vendor to provide one Thermal Oxidizer with a required destruction efficiency on all propane and heavier hydrocarbons of 99.9% .

B2 - Due to low available process gas pressures, vendor to include an induced or forced draft fan with unit.

Process Flows

B2 - The process flow is a CO_2 rich "wet" stream containing significant amounts of N_2 and small amounts of C1 to C7+ hydrocarbons. Stream conditions, gas flow rates, and compositional analysis are as follow:

ACID GAS RATES

Rev	Stream Conditions:		TURN DOWN	NORM	DESIGN
B2	Pressure (PSIG)		**2.00**	**2.00**	**2.00**
B2	Temperature (F)		112.00	112.00	110.00
	Sulfur Content		TRACE	TRACE	TRACE
	Component Mass Rates (LB/HR):				
B2	**Methane**	C1		1.80	1.80
B2	**Ethane**	C2		211.60	211.60
B2	**Propane**	C3		91.30	114.50
B2	**Propene**	C3=		0.00	44.19
B2	**i-Butane**	i-C4		0.93	31.45
B2	**n-Butane**	n-C4		1.29	3.60
B2	**i-Pentane**	i-C5		0.62	16.35
B2	**n-Pentane**	n-C5		0.47	13.36
B2	**n-Hexane**	C6		2.17	11.16
B2	**n-Heptane Plus**	C7 +		0.35	0.35
B2	**Carbon Dioxide**	CO2		7143.0	7143.0
B2	**Water**	H2O		275.73	275.73
B2	**Oxygen**	O2		0.00	13.99
B2	**Nitrogen**	N2		0.00	1458.2
B2	**Di-Ethyl-Amine**	DEA		0.00	0.00
B2	**Total (LB/HR):**		**Note 1**	**7729.3**	**9339.3**
B2	**Avg Mol Wt (LB/LB MOL):**			**41.36**	**38.59**
B2	**Est. Gas LHV (BTU/LB):**			**814**	**964**
B2	**Std Gas Flow (MM SCFD):**			**1.70**	**2.20**
B2	**Std Gas Flow (SCFM):**			**1180**	**1528**

B2 **Note 1: VENDOR TO PRIVIDE MINIMUM TURNDOWN CAPABILITY ASSUMING NORM GAS COMPOSITION.**

Supplemental Fuel

- Additional fuel required to supplement combustion will be pipeline natural gas at 150 psig and ambient temperatures with following composition:

Natural Gas Analysis:

Component		Mole %
Nitrogen	N2	1.3645
Oxygen	O2	0.2324
Carbon Monoxide	CO	0.0124
Carbo Dioxide	CO2	1.4665
Methane	C1	92.9606
Ethane	C2	2.6126
Propane	C3	0.6918
i-Butane	i-C4	0.1946
N-Butane	n-C4	0.1751
i-Pentane	i-C5	0.0662
n-Pentane	n-C5	0.0448
Hexane Plus	C6 +	0.1785
Total		**100.000**

M-040.050192

S & B Engineers and Constructors, Ltd.	SPECIFICATION SHEET	Job No. C-1469	Item No. 100-SK25.002
	"Thermal Oxidizer Package"	P.O. No.	Inq. No.
		By RAP	Date 11/3/2011 Rev. B2

CLIENT	Lone Star NGL	SERVICE	Thermal Oxidizer	No. REQUIRED	1
LOCATION	Mont Belvieu, TX	MANUFACTURER			

Process Requirements

B1 - Thermal oxidizer must comply with the follwing emission limits for the listed products of cumbustion:

REV		
B1	NOx Emission Factor:	0.060 lb / MM BTU
B1	CO Emission Factor:	0.075 lb / MM BTU
B1	VOC Emission Factor:	5.5 lb / MM SCF
B1	PM Emission Factor:	7.6 lb / MM SCF
B1	SOx Emission Factor:	3.42 lb / HR

M-040.050192

APPENDIX D
BACT SUPPORTING DOCUMENTATION

FRAC III PROJECT GHG PSD AIR PERMIT APPLICATION

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

Permit Information													
RBLC ID:	Corporate/ Company Name	Facility Name	State	EPA Region	Permit Number	SIC Code	NAICS Code	Application Accepted Received Date	Permit Issuance Date	Permit Type	Permit URL	Facility Description:	Permit Notes
*NE-0054	CARGILL, INCORPORATED	CARGILL, INCORPORATED	NE	7	12-042	2046	311221		03/01/2013 EST	B: Add new process to existing facility			DRAFT DETERMINATION
*MI-0404	GERDAU MACSTEEL, INC.	GERDAU MACSTEEL, INC.	MI	5	102-12	3312	331111	11/06/2012 ACT	01/04/2013 ACT	D:		Steel Mill	The facility is a steel mini-mill. Gerdau melts steel to produce steel at varying specificatioins to meet customer demands. Steel is melted in an electric arc furnace and processed in the plant. FACILITY-WIDE POLLUTANTS in addition to those below: PM10 +32.4 PM2.5 +33.6 Lead +0.28 GHG +169737 H2SO4 +6.68 DRAFT DETERMINATION
*MI-0404	GERDAU MACSTEEL, INC.	GERDAU MACSTEEL, INC.	MI	5	102-12	3312	331111	11/06/2012 ACT	01/04/2013 ACT	D:		Steel Mill	The facility is a steel mini-mill. Gerdau melts steel to produce steel at varying specificatioins to meet customer demands. Steel is melted in an electric arc furnace and processed in the plant. FACILITY-WIDE POLLUTANTS in addition to those below: PM10 +32.4 PM2.5 +33.6 Lead +0.28 GHG +169737 H2SO4 +6.68 DRAFT DETERMINATION
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*MI-0404	GERDAU MACSTEEL, INC.	GERDAU MACSTEEL, INC.	MI	5	102-12	3312	331111	11/06/2012 ACT	01/04/2013 ACT	D:		Steel Mill	The facility is a steel mini-mill. Gerdau melts steel to produce steel at varying specificatioins to meet customer demands. Steel is melted in an electric arc furnace and processed in the plant. FACILITY-WIDE POLLUTANTS in addition to those below: PM10 +32.4 PM2.5 +33.6 Lead +0.28 GHG +169737 H2SO4 +6.68 DRAFT DETERMINATION

	Process Information						
					Throughput		
RBLC ID:	Process ID	Process Name	Process Type	Primary Fuel	Value	Unit	Process Notes
*NE-0054	*NE-0054-Process 1	Boiler K	11.31	natural gas	300	mmbtu/h	
*MI-0404	*MI-0404-Process 1	Caster (EUCASTER)	81.23	Natural gas	130	T/H liquid steel	The primary fuel is natural gas in oxy-fuel burners. Molten steel produced by the electric arc furnace is delivered to the continuous caster in a ladle via the ladle metallurgy system and twin tank vacuum degasser. The molten steel is gravity fed from the ladle to the tundish. From the tundish, the molten steel flows into the enclosed caster strands. The semi-molten steel is then cut into billets by oxy-fuel cutting torches. The four cutting torches have a combined rated capacity of 4,413 cubic feet of natural gas per hour.
*MI-0404	*MI-0404-Process 1	Melt Shop (FG-MELTSHOP)	81.21	Electric	130	T liquid steel per H	This process is a flexible group which includes an electric arc furnace (EUEAF), a ladle metallurgy station (EULMF), and two vacuum degassers (twin tank) (EUVTD). The limits apply to the whole flexible group, not individual emission units of the group. Also, the primary fuel is electric with Oxy-fuel booster burners. The RBLC process code is 81.210 AND 81.220. The steel is melted in an electric arc furnace using an electric arc along with natural gas fired oxy-fueled burners, which increase the steel melting rate. The molten steel is tapped from the vessel and is covered and transferred to the ladle metallurgy station. After ladle metallurgy is complete, the ladle is covered and transferred to the vacuum degassing station.
*MI-0404	*MI-0404-Process 1	Walking Beam Billet Reheat Furance (EUBILLET-REHEAT)	81.29	Natural gas	260.7	MMBTU/H total burner	A walking beam billet reheat furnace equipped with Ultra-Low NOx burners with the total heat input capacity of 260.7 MMBTU/H.
*MI-0404	*MI-0404-Process 1	Slidegate Heater (EUSLIDEGATEHEATER)	81.29	Natural gas	0		Small, natural-gas fired, internally vented process heater that preheats the submerged entry nozzle (SEN) prior to it being inserted into the caster mold. Molten metal is added after the SEN is in place.

	Emissions Information															
			Emission Limit 1			Emission Limit 2:			Standard Emission Limit:								
RBLC ID:	Process ID	Control Method Description:	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Case-by-Case Basis:	Other Applicable Requirements	Did factors, other then air pollution technology considerations influence the BACT decisions?	Compliance Verified	Cost Verified (Y/N)?	Pollutants/ Compliance Notes
*NE-0054	*NE-0054-Process 1	good combustion practices	0			0			0			BACT-PSD		U	Unknown	No	
*MI-0404	*MI-0404-Process 1	Energy efficiency practices	0			0			0			BACT-PSD	NA	No	No	No	PSD BACT was determined to be energy efficiency practices, an energy efficiency management plan is required for the caster. No numeric BACT limit was given.
*MI-0404	*MI-0404-Process 1		0.16	LB/T LIQUID STEEL	TEST PROTOCOL (PSD BACT)	157365	T/YR	12-MO ROLLING TIME PERIOD (PSD BACT)	0			BACT-PSD	NA	No	No	No	The applicant evaluated carbon sequestration and capture and terrestrial sequestration. Terrestrial sequestration was the lowest cost per ton at $162 per ton. The total overall cost for this project would have been $287,771,970 which does not include annual upkeep. This was found not to be cost effective. BACT was determined to be energy efficiency with an energy efficiency plan for the melt shop.
*MI-0404	*MI-0404-Process 1		119	LB/MMB TU	TEST PROTOCOL (PSD BACT)	98019	T/YR	12-MO ROLLING TIME PERIOD (PSD BACT)	0			BACT-PSD	NA	No	No	No	The applicant evaluated carbon sequestration and capture and terrestrial sequestration. Terrestrial sequestration was the lowest cost per ton at $162 per ton. The total overall cost for this project would have been $287,771.970 which does not include annual upkeep. This was found not to be cost effective. BACT was determined to be energy efficiency with an energy efficiency plan for the melt shop.
*MI-0404	*MI-0404-Process 1	Energy efficiency practices	0			0			0			BACT-PSD	NA	No	No	No	PSD BACT was determined to be energy efficiency practices, an energy efficiency management plan is required. No numeric BACT limit was given.

Permit Information													
RBLC ID:	Corporate/ Company Name	Facility Name	State	EPA Region	Permit Number	SIC Code	NAICS Code	Application Accepted Received Date	Permit Issuance Date	Permit Type	Permit URL	Facility Description:	Permit Notes
*CA-1223	PIO PICO ENERGY CENTER, LLC	PIO PICO ENERGY CENTER	CA	9	SD 11-01	4911	221112	06/14/2012 ACT	11/19/2012 ACT	A: New/Greenfield Facility	http://www.epa.gov/region9/air/permit/r9-permits-issued.html	CONSTRUCTION OF THREE GENERAL ELECTRIC (GE) LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE-GENERATORS (CTGs) RATED AT 100 MW EACH. THE PROJECT WILL HAVE AN ELECTRICAL OUTPUT OF 300 MW.	DRAFT DETERMINATION
*CA-1223	PIO PICO ENERGY CENTER, LLC	PIO PICO ENERGY CENTER	CA	9	SD 11-01	4911	221112	06/14/2012 ACT	11/19/2012 ACT	A: New/Greenfield Facility	http://www.epa.gov/region9/air/permit/r9-permits-issued.html	CONSTRUCTION OF THREE GENERAL ELECTRIC (GE) LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE-GENERATORS (CTGs) RATED AT 100 MW EACH. THE PROJECT WILL HAVE AN ELECTRICAL OUTPUT OF 300 MW.	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*PA-0278	MOXIE ENERGY LLC	MOXIE LIBERTY LLC/ASYLUM POWER PL T	PA	3	08-00045A	491	221112	09/26/2011 ACT	10/10/2012 ACT	A: New/Greenfield Facility			The project consists of two identical 1 x 1 power blocks, and each block includes a combustion gas turbine and a steam turbine. Each combined-cycle process will also include a heat recovery steam generator and supplemental duct burners. Additionally, one diesel-fired emergency generator, one diesel-fired fire water pump, two diesel fuel storage tanks, two lube oil storage tanks, and one aqueous ammonia storage tank were proposed to be constructed and operated. Each combined-cycle process will be rated at 468 MW or less. DRAFT DETERMINATION
*VA-0319	GATEWAY GREEN ENERGY	GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT	VA	3	52375-002	4911	221112	01/11/2012 ACT	08/27/2012 ACT	A: New/Greenfield Facility	http://www.deq.virginia.gov/Portals/0/DEQ/Air/Permitting/PSDPermits/52375_Permit.pdf	Combined cycle electrical power generating facility (160 MW), consisting of two combustion turbines (Rolls Royce Trent 60 WLE) with associated HRSG and no duct burning.	DRAFT DETERMINATION

	Process Information						
					Throughput		
RBLC ID:	Process ID	Process Name	Process Type	Primary Fuel	Value	Unit	Process Notes
*CA-1223	*CA-1223-Process 1	COMBUSTION TURBINES (NORMAL OPERATION)	15.11	NATURAL GAS	300	MW	THREE SIMPLE CYCLE COMBUSTION TURBINE GENERATORS (CTG). EACH CTG RATED AT 100 MW (NOMINAL NET).
*CA-1223	*CA-1223-Process 1	CIRCUIT BREAKERS	99.999		0		3 SWITCHYARD AND 2 GENERATOR BREAKERS CONTAINING SF6.
*IA-0105	*IA-0105-Process 1	Primary Reformer	61.012	natural gas	1.13	million cubic feet/hr	
*IA-0105	*IA-0105-Process 1	CO2 Regenerator	61.012		3012	metric tons/day	
*IA-0105	*IA-0105-Process 1	Urea Ammonia Nitrate (UAN) Mixing Tank	61.012		0		The maximum capacity of the tank is 5,400 metric tons and it has an Acid Scrubber to control ammonia.
*IA-0105	*IA-0105-Process 1	Urea Synthesis	61.012		2500	metric tons/day	There is an Acid Scrubber for ammonia control
*IA-0105	*IA-0105-Process 1	Nitric Acid Plant	62.014		1905	metric tons/day	
*IA-0105	*IA-0105-Process 1	Auxiliary Boiler	11.31	natural gas	472.4	MMBTU/hr	
*IA-0105	*IA-0105-Process 1	Ammonia Flare	19.31	natural gas	0.4	MMBTU/H	There are four (4) natural gas pilots
*IA-0105	*IA-0105-Process 1	Emergency Generator	17.11	diesel fuel	142	GAL/H	rated @ 2,000 KW
*IA-0105	*IA-0105-Process 1	Fire Pump	17.21	diesel fuel	14	GAL/H	rated @ 235 KW
*IA-0105	*IA-0105-Process 1	Startup Heater	12.31	Natural gas	110.12	MMBTU/H	
*PA-0278	*PA-0278-Process 1	Combined-cycle Turbines (2) - Natural gas fired	15.2	Natural Gas	3277	MMBtu/hr	Two combine cycle Turbines, each with a combustion turbine and heat recovery steam generator with duct burner. Each combined-cycle process will be rated at 468 MW or less. The heat input rating of each combustion gas turbine is 2890 MMBtu/hr (HHV) or less, and the heat input rating of each supplemental duct burner is equal to 387 MMBtu/hr (HHV) or less.
*VA-0319	*VA-0319-Process 1	COMBUSTION TURBINES, (2)	15.21	Natural Gas	593	MMBTU/H	Burns primarily natural gas but has the capacity to burn up to 500 hours of ultra low sulfur diesel fuel (ULSD) as backup.

	Emissions Information																
			Emission Limit 1			Emission Limit 2:			Standard Emission Limit:								
RBLC ID:	Process ID	Control Method Description:	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Case-by-Case Basis:	Other Applicable Requirements	Did factors, other then air pollution technology considerations influence the BACT decisions?	Compliance Verified	Cost Verified (Y/N)?	Pollutants/ Compliance Notes
*CA-1223	*CA-1223-Process 1		1328	LB/MW-HR	GROSS OUTPUT	720	HR	ROLLING OPERATING HOUR AVG	0			BACT-PSD		U	Unknown	No	
*CA-1223	*CA-1223-Process 1	INSTALL, OPERATE, AND MAINTAIN ENCLOSED-PRESSURE SF6 CIRCUIT BREAKERS WITH A MAXIMUM ANNUAL LEAKAGE RATE OF 0.5% BY WEIGHT	40.2	TPY	TONS PER CALENDAR YEAR	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	good combustion practices	596905	TONS/YR	ROLLING 12 MONTH TOTAL	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	good operational practices	1211847	TONS/YR	ROLLING 12 MONTH TOTAL	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	good operational practices	4.92	TONS/YR	ROLLING 12 MONTH TOTAL	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	good operational practices	724.5	TONS/YR	ROLLING 12 MONTH TOTAL	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	De-N2O system	29543	TONS/YR	ROLLING 12 MONTH TOTAL	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	good combustion practices	51748	TONS/YR	ROLLING 12 MONTH TOTAL	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	work practice/good combustion practices	0			0			0			BACT-PSD		U	Unknown	No	There is no numeric emission limit in the permit.
*IA-0105	*IA-0105-Process 1	good combustion practices	788.5	TONS/YR	ROLLING 12 MONTH TOTAL	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	good combustion practices	91	TONS/YR	ROLLING 12 MONTH TOTAL	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	good combustion practices	638	TONS/YR	ROLLING 12 MONTH TOTAL	0			0			BACT-PSD		U	Unknown	No	
*PA-0278	*PA-0278-Process 1	Good combustion practices.	1480086	TPY	468 MW POWERBLOCK	1388540	TPY	454 MW POWERBLOCK	0			BACT-PSD		U	Unknown	No	
*VA-0319	*VA-0319-Process 1	Controlled by the use of low carbon fuels and high efficiency design. The heat rate shall be no greater than 8,983 Btu/kW-h (HHV, gross).	295961	T/YR	12 MO ROLLING AVG	1050	LB/MWH	12 MO AVERAGE	0			BACT-PSD	NSPS	Y	Unknown	No	Initial compliance testing, using ASME Performance Test Code on Overall Plant Performance (ASME PTC 46-1996).

Permit Information												
RBLC ID:	**Corporate/ Company Name**	**Facility Name**	**State**	**EPA Region**	**Permit Number**	**SIC Code**	**NAICS Code**	**Application Accepted Received Date**	**Permit Issuance Date**	**Permit Type**	**Permit URL**	**Facility Description:**	**Permit Notes**
*VA-0319	GATEWAY GREEN ENERGY	GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT	VA	3	52375-002	4911	221112	01/11/2012 ACT	08/27/2012 ACT	A: New/Greenfield Facility	http://www.deq.virginia.gov/Portals/0/DEQ/Air/Permitting/PSDPermits/52375_Permit.pdf	Combined cycle electrical power generating facility (160 MW), consisting of two combustion turbines (Rolls Royce Trent 60 WLE) with associated HRSG and no duct burning.	DRAFT DETERMINATION
*VA-0319	GATEWAY GREEN ENERGY	GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT	VA	3	52375-002	4911	221112	01/11/2012 ACT	08/27/2012 ACT	A: New/Greenfield Facility	http://www.deq.virginia.gov/Portals/0/DEQ/Air/Permitting/PSDPermits/52375_Permit.pdf	Combined cycle electrical power generating facility (160 MW), consisting of two combustion turbines (Rolls Royce Trent 60 WLE) with associated HRSG and no duct burning.	DRAFT DETERMINATION
LA-0263	PHILLIPS 66 COMPANY	ALLIANCE REFINERY	LA	6	PSD-LA-760	2911	324110	12/19/2011 ACT	07/25/2012 ACT	B: Add new process to existing facility		PETROLEUM REFINERY. THE PROJECT ENTAILS CONSTRUCTION OF A NEW 20 MM SCF/DAY STEAM METHANE REFORMER TO MAKE HYDROGEN NEEDED TO PRODUCE ULTRA LOW SULFUR DIESEL.	
LA-0263	PHILLIPS 66 COMPANY	ALLIANCE REFINERY	LA	6	PSD-LA-760	2911	324110	12/19/2011 ACT	07/25/2012 ACT	B: Add new process to existing facility		PETROLEUM REFINERY. THE PROJECT ENTAILS CONSTRUCTION OF A NEW 20 MM SCF/DAY STEAM METHANE REFORMER TO MAKE HYDROGEN NEEDED TO PRODUCE ULTRA LOW SULFUR DIESEL.	
LA-0260	WILLIAMS OLEFINS, LLC	GEISMAR ETHYLENE PLANT	LA	6	PSD-LA-759	2869	325110	12/13/2011 ACT	04/11/2012 ACT	B: Add new process to existing facility		Project to install 2 cracking furnaces at the Ethylene Plant to increase production from 1.4 to 1.95 billion lbs/yr	Complete application date = Administrative Complete date
VT-0037	BEAVER WOOD ENERGY FAIR HAVEN, LLC	BEAVER WOOD ENERGY FAIR HAVEN	VT	1	AP-11-015	4911	221119	02/22/2011 ACT	02/10/2012 ACT	A: New/Greenfield Facility	http://www.anr.state.vt.us/air/Permitting/docs/ap01015.pdf	The facility is a proposed 34 MW (gross) wood fired EGU co-located with a 115,000 ton/yr wood pellet manufacturing plant.	
VT-0037	BEAVER WOOD ENERGY FAIR HAVEN, LLC	BEAVER WOOD ENERGY FAIR HAVEN	VT	1	AP-11-015	4911	221119	02/22/2011 ACT	02/10/2012 ACT	A: New/Greenfield Facility	http://www.anr.state.vt.us/air/Permitting/docs/ap01015.pdf	The facility is a proposed 34 MW (gross) wood fired EGU co-located with a 115,000 ton/yr wood pellet manufacturing plant.	
GA-0147	PYRAMAX CERAMICS, LLC	PYRAMAX CERAMICS, LLC - KING'S M:U FACILITY	GA	4	3295-163-0035-P-01-0	3295	212324	07/26/2011 ACT	01/27/2012 ACT	A: New/Greenfield Facility	HTTP://WWW.GEORGIAAIR.ORG/AIRPERMIT	THIS FACILITY IS A KAOLIN CLAY PROCESSING (CERAMIC PROPPANT MANUFACTURING) PLANT. THE FACILITY WILL USE SPRAY DRYERS AND CALCINERS TO PROCESS THE CLAY.	
GA-0147	PYRAMAX CERAMICS, LLC	PYRAMAX CERAMICS, LLC - KING'S M:U FACILITY	GA	4	3295-163-0035-P-01-0	3295	212324	07/26/2011 ACT	01/27/2012 ACT	A: New/Greenfield Facility	HTTP://WWW.GEORGIAAIR.ORG/AIRPERMIT	THIS FACILITY IS A KAOLIN CLAY PROCESSING (CERAMIC PROPPANT MANUFACTURING) PLANT. THE FACILITY WILL USE SPRAY DRYERS AND CALCINERS TO PROCESS THE CLAY.	
GA-0147	PYRAMAX CERAMICS, LLC	PYRAMAX CERAMICS, LLC - KING'S M:U FACILITY	GA	4	3295-163-0035-P-01-0	3295	212324	07/26/2011 ACT	01/27/2012 ACT	A: New/Greenfield Facility	HTTP://WWW.GEORGIAAIR.ORG/AIRPERMIT	THIS FACILITY IS A KAOLIN CLAY PROCESSING (CERAMIC PROPPANT MANUFACTURING) PLANT. THE FACILITY WILL USE SPRAY DRYERS AND CALCINERS TO PROCESS THE CLAY.	

	Process Information						
					Throughput		
RBLC ID:	Process ID	Process Name	Process Type	Primary Fuel	Value	Unit	Process Notes
*VA-0319	*VA-0319-Process 1	FIRE WATER PUMP	17.21	diesel (ultra low sulfur)	1.86	MMBTU/H	500 H/Yr operation
*VA-0319	*VA-0319-Process 1	ELECTRIC CIRCUIT BREAKERS, (4)	99.999		60	LB/SF6	Enclosed pressure circuit breaker.
LA-0263	LA-0263-Process 1	STEAM METHANE REFORMER (2291-SMR, EQT 0196)	12.390	REFINERY FUEL GAS	216	MMBTU/H	AVERAGE HEAT INPUT: 180 MM BTU/HR NATURAL GAS IS ALSO USED AS A FUEL.
LA-0263	LA-0263-Process 2	HYDROGEN PLANT FUGITIVES (2291-FF, FUG 0026)	99.999		0		
LA-0260	LA-0260-Process 1	Cracking Furnaces 95 and 96	12.310	natural gas	180	MMBTU/H	(each)
VT-0037	VT-0037-Process 1	Main Boiler	11.120	wood	482	MMBTU/H	
VT-0037	VT-0037-Process 2	Pellet Plant - burner & rotary dryer	30.999	wood	115000	T/YR	Throughput is for finished wood pellet product. There is a wood fired heating unit, using a Coen LowNOx burner rated at 30 MMBtu/hr used to provide hot air/exhaust for the drying of wood in the rotary dryer. Additional drying heat for the rotary dryer will come from a portion of the exhaust gas from the Main Boiler at the facility.
GA-0147	GA-0147-Process 1	SPRAY DRYERS/PETTETIZERS	90.009	NATURAL GAS	75	MMBTU/H	THE FACILITY HAS TWO SPRAY DRYERS
GA-0147	GA-0147-Process 2	BOILERS	19.600	NATURAL GAS	9.8	MMBTU/H	THE FACILITY HAS TWO BOILERS
GA-0147	GA-0147-Process 3	CALCINERS/KILNS	90.017	NATURAL GAS	4.9	MMBTU/H	THE FACILITY HAS TWO CALCINERS/KILNS

	Emissions Information																
			Emission Limit 1			Emission Limit 2:			Standard Emission Limit:								
RBLC ID:	Process ID	Control Method Description:	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Case-by-Case Basis:	Other Applicable Requirements	Did factors, other then air pollution technology considerations influence the BACT decisions?	Compliance Verified	Cost Verified (Y/N)?	Pollutants/ Compliance Notes
*VA-0319	*VA-0319-Process 1	Fuel-efficient design	30.5	T/YR	12 MO ROLLING AVG	0						BACT-PSD	NSPS , MACT	U	Unknown	No	
*VA-0319	*VA-0319-Process 1	Enclosed pressure circuit breaker.	28.6	T/YR	12 MO AVG	0						BACT-PSD		Y	Unknown	No	Enclosed pressure circuit breaker, with a maximum annual leakage rate of 1.0% and a leak detection system (gas density gauges).
LA-0263	LA-0263-Process 1	SELECTION OF MOST EFFICIENT H2 PURIFICATION PROCESS - PRESSURE SWING ADSORPTION, HEAT RECOVERY AIR PREHEATER (UNLESS HEAT FROM SMR STACK IS RECOVERED ELSEWHERE), ADIABATIC PRE-REFORMER, MAINTENANCE AND FOULING CONTROL, COMBUSTION AIR AND FEED/STEAM PREHEAT, COMBUSTION AIR CONTROLS (LIMITING EXCESS AIR), PROCESS INTEGRATION, FURNACE CONTROLS (GOOD COMBUSTION PRACTICES), NEW BURNER DESIGNS	183784	T/YR	12-MONTH ROLLING AVERAGE	0			0.05	LB/SCF H2 PRODUCTION	12-MONTH ROLLING AVERAGE	BACT-PSD		U	Unknown	No	
LA-0263	LA-0263-Process 2	IMPLEMENTATION OF THE LOUISIANA REFINERY MACT LEAK DETECTION AND REPAIR PROGRAM; MONITORING FOR TOTAL HYDROCARBON CONTENT INSTEAD OF VOC	0			0			0			BACT-PSD		U	Unknown	No	
LA-0260	LA-0260-Process 1	1) low-emitting feedstocks, 2) energy efficient equipment, 3) process design improvement, 4) lew-emitting and low- carbon fuel (>25 vol% hydrogen, annual ave.)	0			0			0			BACT-PSD		U	Unknown	No	
VT-0037	VT-0037-Process 1	Implementing energy efficiency and good operating and maintenance practices.	2993	LB/MW GROSS ELEC OUT	30-DAY ROLLING AVERAGE	0			0			BACT-PSD		U	Unknown	No	GHG emission limit is 2993 lb CO2e per MW of gross electric output.
VT-0037	VT-0037-Process 2	The use of waste heat from the Main Boiler to provide approximately 30% of the energy for drying the wood used in manufacturing pellets.	427	LB/T	MONTHLY AVERAGE	0			0			BACT-PSD		U	Unknown	No	The limit is to be phased in over three years.
GA-0147	GA-0147-Process 1	Good Heating Insulation, Good Combustion Practices	44446	T/12-MO ROLLIN G AVG		0			0			BACT-PSD		U	Unknown	No	
GA-0147	GA-0147-Process 2	Good Combustion Practices, design, and thermal insulation.	5809	T/12-MO ROLLIN G AVG		0			0			BACT-PSD		U	Unknown	No	
GA-0147	GA-0147-Process 3	Good Heat Insulation, Heat Recovery, Good Combustion Practices	436	LB/T	PROD OF CO2E, 12-MO ROLL TOTAL	0			0			BACT-PSD		U	Unknown	No	

Permit Information													
RBLC ID:	Corporate/ Company Name	Facility Name	State	EPA Region	Permit Number	SIC Code	NAICS Code	Application Accepted Received Date	Permit Issuance Date	Permit Type	Permit URL	Facility Description:	Permit Notes
GA-0147	PYRAMAX CERAMICS, LLC	PYRAMAX CERAMICS, LLC - KING'S M:U FACILITY	GA	4	3295-163-0035-P-01-0	3295	212324	07/26/2011 ACT	01/27/2012 ACT	A: New/Greenfield Facility	HTTP://WWW.GEORGIAAIR.ORG/AIRPERMIT	THIS FACILITY IS A KAOLIN CLAY PROCESSING (CERAMIC PROPPANT MANUFACTURING) PLANT. THE FACILITY WILL USE SPRAY DRYERS AND CALCINERS TO PROCESS THE CLAY.	
IA-0101	INTERSTATE POWER & LIGHT	OTTUMWA GENERATING STATION	IA	7	78-A-019-P10	4911	221112	05/20/2011 ACT	01/12/2012 ACT	C: Modify process at existing facility	https://aqbweb.iowadnr.gov/psd/9007001/PSD_PN_11-219/78A019P10_boiler.pdf	Electric Utility	This project was to add controls for PM, SO2 and Hg. It resulted in an increase in hours and was major for only CO2e and CO.
*IL-0111	UNIVERSAL CEMENT	UNIVERSAL CEMENT	IL	5	08120011	3241	327310		12/20/2011 ACT	A: New/Greenfield Facility		Portland Cement Mfg. - includes a preheater/precalciner kiln with in-line raw mill, a clinker cooler, a finish mill, and storage & handling of materials.	GHG = 1,105,823 PM10 = 134.6 PM2.5 = 99.5 H2S = 9.9
LA-0256	WESTLAKE VINYLS COMPANY LP	COGENERATION PLANT	LA	6	PSD-LA-754	4939	221112	01/12/2011 ACT	12/06/2011 ACT	B: Add new process to existing facility		COGENERATION PLANT AT SYNTHETIC ORGANIC CHEMICAL MANUFACTURING FACILITY	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS "FWE" REPRESENT POTENTIAL EMISSIONS ASSOCIATED WITH THE COGENERATION PLANT. NOX "NETTED OUT" OF PSD/NNSR.
LA-0256	WESTLAKE VINYLS COMPANY LP	COGENERATION PLANT	LA	6	PSD-LA-754	4939	221112	01/12/2011 ACT	12/06/2011 ACT	B: Add new process to existing facility		COGENERATION PLANT AT SYNTHETIC ORGANIC CHEMICAL MANUFACTURING FACILITY	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS "FWE" REPRESENT POTENTIAL EMISSIONS ASSOCIATED WITH THE COGENERATION PLANT. NOX "NETTED OUT" OF PSD/NNSR.
LA-0257	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	SABINE PASS LNG TERMINAL	LA	6	PSD-LA-703(M3)	4925	221210	12/22/2010 ACT	12/06/2011 ACT	B: Add new process to existing facility		A liquefaction section of the terminal which will include 24 compressor turbines, two generator turbines, two generator engines, flares, acid gas vents, and fugitives	
LA-0257	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	SABINE PASS LNG TERMINAL	LA	6	PSD-LA-703(M3)	4925	221210	12/22/2010 ACT	12/06/2011 ACT	B: Add new process to existing facility		A liquefaction section of the terminal which will include 24 compressor turbines, two generator turbines, two generator engines, flares, acid gas vents, and fugitives	
LA-0257	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	SABINE PASS LNG TERMINAL	LA	6	PSD-LA-703(M3)	4925	221210	12/22/2010 ACT	12/06/2011 ACT	B: Add new process to existing facility		A liquefaction section of the terminal which will include 24 compressor turbines, two generator turbines, two generator engines, flares, acid gas vents, and fugitives	
LA-0257	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	SABINE PASS LNG TERMINAL	LA	6	PSD-LA-703(M3)	4925	221210	12/22/2010 ACT	12/06/2011 ACT	B: Add new process to existing facility		A liquefaction section of the terminal which will include 24 compressor turbines, two generator turbines, two generator engines, flares, acid gas vents, and fugitives	
LA-0257	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	SABINE PASS LNG TERMINAL	LA	6	PSD-LA-703(M3)	4925	221210	12/22/2010 ACT	12/06/2011 ACT	B: Add new process to existing facility		A liquefaction section of the terminal which will include 24 compressor turbines, two generator turbines, two generator engines, flares, acid gas vents, and fugitives	
LA-0257	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	SABINE PASS LNG TERMINAL	LA	6	PSD-LA-703(M3)	4925	221210	12/22/2010 ACT	12/06/2011 ACT	B: Add new process to existing facility		A liquefaction section of the terminal which will include 24 compressor turbines, two generator turbines, two generator engines, flares, acid gas vents, and fugitives	
LA-0257	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	SABINE PASS LNG TERMINAL	LA	6	PSD-LA-703(M3)	4925	221210	12/22/2010 ACT	12/06/2011 ACT	B: Add new process to existing facility		A liquefaction section of the terminal which will include 24 compressor turbines, two generator turbines, two generator engines, flares, acid gas vents, and fugitives	

	Process Information						
					Throughput		
RBLC ID:	Process ID	Process Name	Process Type	Primary Fuel	Value	Unit	Process Notes
GA-0147	GA-0147-Process 4	500 KW EMERGENCY DIESEL GENERATORS	19.900		500	KW each	THE FACILITY HAS FOUR 500 KW EMERGENCY DIESEL GENERATORS
IA-0101	IA-0101-Process 1	Boiler #1	11.110	PRB Coal	8669	MMBTU/H	
*IL-0111	*IL-0111-Process 1	KILN WITH IN-LINE RAW MILL	90.028	COAL, PETCOKE, SCRAP TIRES	1.25	MILLION TPY CLINKER	
LA-0256	LA-0256-Process 1	COGENERATION TRAINS 1-3 (1-10, 2-10, 3-10)	15.210	NATURAL GAS	475	MMBTU/H	EACH COGEN TRAIN CONSISTS OF A 50 MW GE LM6000 PF SPRINT TURBINE AND A HEAT RECOVERY STEAM GENERATOR EQUIPPED WITH A 70 MM BTU/HR DUCT BURNER.
LA-0256	LA-0256-Process 2	EMERGENCY GENERATOR	17.130	NATURAL GAS	1818	HP	NON-EMERGENCY OPERATION IS LIMITED TO 52 HR/YR.
LA-0257	LA-0257-Process 1	Generator Engines (2)	17.130	Natural Gas	2012	hp	
LA-0257	LA-0257-Process 2	Combined Cycle Refrigeration Compressor Turbines (8)	15.210	natural gas	286	MMBTU/H	GE LM2500+G4
LA-0257	LA-0257-Process 3	Simple Cycle Generation Turbines (2)	15.110	Natural Gas	286	MMBTU/H	GE LM2500+G4
LA-0257	LA-0257-Process 4	Acid Gas Vents (4)	50.999		0		
LA-0257	LA-0257-Process 5	Marine Flare	19.390	natural gas	1590	MMBTU/H	
LA-0257	LA-0257-Process 6	Wet/Dry Gas Flares (4)	19.390	natural gas	0.26	MMBTU/H	
LA-0257	LA-0257-Process 7	Fugitive Emissions	50.999		0		

	Emissions Information																
			Emission Limit 1			Emission Limit 2:			Standard Emission Limit:								
RBLC ID:	Process ID	Control Method Description:	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Case-by-Case Basis:	Other Applicable Requirements	Did factors, other then air pollution technology considerations influence the BACT decisions?	Compliance Verified	Cost Verified (Y/N)?	Pollutants/ Compliance Notes
GA-0147	GA-0147-Process 4		153	T/12-MO ROLLIN G AVG	COMBINED EMISSIONS	0			0			BACT-PSD	MACT , NSPS	U	Unknown	No	
IA-0101	IA-0101-Process 1	Good Combustion Practices	8000325	T/YR	ROLLING 12 MONTH TOTAL	0			0			BACT-PSD		U	Unknown	No	
*IL-0111	*IL-0111-Process 1	MULTI-STAGE PREHEATER/PRECALCINER KILN WITH SELECTION OF REFRACTORY AND A KILN SEAL MANAGEMENT PROGRAM.	1860	LB/TON CLINKE R	ANNUAL 12 MONTH ROLLING AVERAGE	0			0			BACT-PSD		N	Unknown	No	
LA-0256	LA-0256-Process 1	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES	55576.77	LB/H	HOURLY MAXIMUM	0			0			BACT-PSD	OPERATING PERMIT	U	Unknown	No	IN ADDITION, AN ANNUAL LIMIT OF 243,426.26 TPY WAS ESTABLISHED BY THE ACCOMPANYING TITLE V PERMIT (3090-V0).
LA-0256	LA-0256-Process 2	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES	1509.23	LB/H	HOURLY MAXIMUM	0			0			BACT-PSD	OPERATING PERMIT	U	Unknown	No	IN ADDITION, AN ANNUAL LIMIT OF 39.24 TPY WAS ESTABLISHED BY THE ACCOMPANYING TITLE V PERMIT (3090-V0).
LA-0257	LA-0257-Process 1	Fueled by natural gas, good combustion/operating practices	412	TONS/Y R	ANNUAL MAXIMUM	0			0			BACT-PSD		U	Unknown	No	
LA-0257	LA-0257-Process 2	Good combustion/operating practices and fueled by natural gas - use GE LM2500+G4 turbines	4872107	TONS/YE AR	ANNUAL MAXIMUM FROM THE FACILITYWI DE	0			0			BACT-PSD		U	Unknown	No	co2(e)
LA-0257	LA-0257-Process 3	Good combustion/operating practices and fueled by natural gas - use GE LM2500+G4 turbines	4872107	TONS/Y R	ANNUAL MAXIMUM FROM THE FACILITYWI DE	0			0			BACT-PSD		U	Unknown	No	CO2(e)
LA-0257	LA-0257-Process 4		39.29	LB/H	HOURLY MAXIMUM	172.09	TONS/Y R	ANNUAL MAXIMUM	0			BACT-PSD		U	Unknown	No	CO2(e)
LA-0257	LA-0257-Process 5	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	2909	TONS/Y R	ANNUAL MAXIMUM	0			0			BACT-PSD		U	Unknown	No	CO2(e)
LA-0257	LA-0257-Process 6	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	133	TONS/Y R	ANNUAL MAXIMUM	0			0			BACT-PSD		U	Unknown	No	CO2(e)
LA-0257	LA-0257-Process 7	conduct a leak detection and repair (LDAR) program	89629	TONS/Y R	ANNUAL MAXIMUM	0			0			BACT-PSD		U	Unknown	No	CO2(e)

	Permit Information												
RBLC ID:	Corporate/ Company Name	Facility Name	State	EPA Region	Permit Number	SIC Code	NAICS Code	Application Accepted Received Date	Permit Issuance Date	Permit Type	Permit URL	Facility Description:	Permit Notes
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/eepsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/eepsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/eepsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/eepsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/eepsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/eepsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/eepsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/eepsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/eepsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	DRAFT DETERMINATION
*SC-0142	SHOWA DENKO CARBON, INC.		SC	4	0900-0025-CZ	3624		08/11/2011 ACT	06/08/2012 ACT	A: New/Greenfield Facility		GRAPHITE ELECTRODE MANUFACTURING FACILITY.	
*SC-0142	SHOWA DENKO CARBON, INC.		SC	4	0900-0025-CZ	3624		08/11/2011 ACT	06/08/2012 ACT	A: New/Greenfield Facility		GRAPHITE ELECTRODE MANUFACTURING FACILITY.	
*SC-0142	SHOWA DENKO CARBON, INC.		SC	4	0900-0025-CZ	3624		08/11/2011 ACT	06/08/2012 ACT	A: New/Greenfield Facility		GRAPHITE ELECTRODE MANUFACTURING FACILITY.	
*SC-0142	SHOWA DENKO CARBON, INC.		SC	4	0900-0025-CZ	3624		08/11/2011 ACT	06/08/2012 ACT	A: New/Greenfield Facility		GRAPHITE ELECTRODE MANUFACTURING FACILITY.	
*SC-0142	SHOWA DENKO CARBON, INC.		SC	4	0900-0025-CZ	3624		08/11/2011 ACT	06/08/2012 ACT	A: New/Greenfield Facility		GRAPHITE ELECTRODE MANUFACTURING FACILITY.	
*AK-0076	EXXON MOBIL CORPORATION	POINT THOMSON PRODUCTION FACILITY	AK	10	AQ1201CPT01	1382	211111	04/09/2012 ACT	08/20/2012 ACT	A: New/Greenfield Facility		Oil Gas exploration and production facility	Establish a new facility in the North Slope of Alaska
*AK-0076	EXXON MOBIL CORPORATION	POINT THOMSON PRODUCTION FACILITY	AK	10	AQ1201CPT01	1382	211111	04/09/2012 ACT	08/20/2012 ACT	A: New/Greenfield Facility		Oil Gas exploration and production facility	Establish a new facility in the North Slope of Alaska
*AK-0076	EXXON MOBIL CORPORATION	POINT THOMSON PRODUCTION FACILITY	AK	10	AQ1201CPT01	1382	211111	04/09/2012 ACT	08/20/2012 ACT	A: New/Greenfield Facility		Oil Gas exploration and production facility	Establish a new facility in the North Slope of Alaska
*AK-0076	EXXON MOBIL CORPORATION	POINT THOMSON PRODUCTION FACILITY	AK	10	AQ1201CPT01	1382	211111	04/09/2012 ACT	08/20/2012 ACT	A: New/Greenfield Facility		Oil Gas exploration and production facility	Establish a new facility in the North Slope of Alaska
*AK-0076	EXXON MOBIL CORPORATION	POINT THOMSON PRODUCTION FACILITY	AK	10	AQ1201CPT01	1382	211111	04/09/2012 ACT	08/20/2012 ACT	A: New/Greenfield Facility		Oil Gas exploration and production facility	Establish a new facility in the North Slope of Alaska
*AK-0076	EXXON MOBIL CORPORATION	POINT THOMSON PRODUCTION FACILITY	AK	10	AQ1201CPT01	1382	211111	04/09/2012 ACT	08/20/2012 ACT	A: New/Greenfield Facility		Oil Gas exploration and production facility	Establish a new facility in the North Slope of Alaska
*MN-0085	ESSAR STEEL MINNESOTA LLC	ESSAR STEEL MINNESOTA LLC	MN	5	06100067-004	3312	331111	10/19/2011 ACT	05/10/2012 ACT	A: New/Greenfield Facility	HTTP://WWW.PCA.STATE.MN.US/INDEX.PHP/VIEW-DOCUMENT.HTML?GID=17628	ESSAR STEEL LLC (ESSAR) IS A TACONITE ORE MINING AND PROCESSING FACILITY THAT ALSO PRODUCES FINISHED STEEL. ESSAR IS LOCATED IN NORTHERN MINNESOTA ON THE WESTERN END OF THE BIWABIK IRON FORMATION NEAR NASHWAUK. ESSAR IS CURRENTLY IN THE PROCESS OF CONSTRUCTING AN APPROXIMATELY $1.6 BILLION MINE MOUTH ELECTRIC ARC FURNACE STEEL MILL. ESSAR WILL BE THE ONLY FULLY INTEGRATED STEELMAKING FACILITY IN THE UNITED STATES. THE KEY PROJECT FEATURES AND THEIR NOMINAL CAPACITIES ARE: - AN OPEN PIT TACONITE MINE CAPABLE OF MINING APPROXIMATELY 24,000,000 TONNE/YR OF ORE. - A CRUSHER, CONCENTRATOR WITH ASSOCIATED TAILINGS BASIN, PRODUCING APPROXIMATELY 7,000,000 TONNE/YR OF CONCENTRATE. - A PELLETIZER THAT CAN PRODUCE APPROXIMATELY 6,500,000 TONNE/YEAR OF HIGH FLUX OXIDE PELLETS OR 7,000,000 TONNE/YR OF LOW FLUX OXIDE/DIRECT REDUCED IRON (DRI) GRADE PELLETS. - A DRI FACILITY PRODUCING APPROXIMATELY 1,800,000 TONNE/YR OF IRON PELLETS FOR DIRECT FEED FOR STEEL PRODUCTION. - AN ELECTRIC ARC FURNACE	THE MINNESOTA DEPARTMENT OF NATURAL RESOURCES (DNR) CONDUCTED A SUPPLEMENTAL ENVIRONMENTAL IMPACT STATEMENT (SEIS) TO EVALUATE THE PROPOSED PROJECT. ON DECEMBER 29, 2011, THE MN DNR DETERMINED THAT THE SEIS WAS ADEQUATE. MORE INFORMATION IS AVAILABLE AT: HTTP://FILES.DNR.STATE.MN.US/INPUT/ENVIRONMENTALREVIEW/ESSAR/ESSAR_FINAL_SEIS.PDF THE U.S. FISH AND WILDLIFE SERVICE EVALUATED THE NEED FOR A REVIEW OF THE IMPACT ON ENDANGERED SPECIES DUE TO THE ESSAR PROJECT AND DETERMINED THAT THE REVIEW WAS NOT NECESSARY. AIR QUALITY MODELING TO DEMONSTRATE COMPLIANCE WITH THE NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS) AND MINNESOTA AMBIENT AIR QUALITY STANDARDS (MAAQS) WAS PERFORMED FOR PM10, PM2.5, NOX, SO2, PB AND CO. THE ANALYSIS DEMONSTRATED THAT EMISSIONS FOR POLLUTANTS MODELED WOULD MEET THE NAAQS AND MAAQS. CLASS I INCREMENT ANALYSIS WAS DONE USING CALPUFF. MODELING RESULTS INDICATED THAT THE EMISSIONS ASSOCIATED WITH THE ESSAR PROJECT WILL NOT SIGNIFICANTLY DETERIORATE THE AIR QUALITY IN CLASS I AREAS. CLASS II INCREMENT ANALYSIS WAS DONE USING AERMOD AND BUILDING DOWNWASH PREDICTIONS WERE PREDICTED USING BPIP-PRIME. FUGITIVE SOURCES AS WELL AS EMISSIONS FROM MODIFIED AND ADDED STACKS WERE MODELED. BACKUP GENERATORS AND STACKS USED ONLY DURING PLANT UPSET WERE NOT INCLUDED IN THE

RBLC ID:	Process ID	Process Name	Process Type	Primary Fuel	Throughput Value	Throughput Unit	Process Notes
*IA-0105	*IA-0105-Process 1	Primary Reformer	61.012	natural gas	1.13	million cubic feet/hr	
*IA-0105	*IA-0105-Process 1	CO2 Regenerator	61.012		3012	metric tons/day	
*IA-0105	*IA-0105-Process 1	Urea Ammonia Nitrate (UAN) Mixing Tank	61.012		0		The maximum capacity of the tank is 5,400 metric tons and it has an Acid Scrubber to control ammonia.
*IA-0105	*IA-0105-Process 1	Urea Synthesis	61.012		2500	metric tons/day	There is an Acid Scrubber for ammonia control
*IA-0105	*IA-0105-Process 1	Auxiliary Boiler	11.31	natural gas	472.4	MMBTU/hr	
*IA-0105	*IA-0105-Process 1	Ammonia Flare	19.31	natural gas	0.4	MMBTU/H	There are four (4) natural gas pilots
*IA-0105	*IA-0105-Process 1	Emergency Generator	17.11	diesel fuel	142	GAL/H	rated @ 2,000 KW
*IA-0105	*IA-0105-Process 1	Fire Pump	17.21	diesel fuel	14	GAL/H	rated @ 235 KW
*IA-0105	*IA-0105-Process 1	Startup Heater	12.31	Natural gas	110.12	MMBTU/H	
*SC-0142	*SC-0142-Process 1	HOT OIL HEATER	19.6	NATURAL GAS	5	MMBTU/H	THERE WILL BE A HOT OIL HEATER FOR THE MILL, MIX, AND EXTRUSION PROCESS AND A HOT OIL HEATER FOR THE PITCH IMPREGNATION PROCESS (EACH SIZED AT 5 MMBTU/HR).
*SC-0142	*SC-0142-Process 2	CARBOTTOM FURNACES	19.6	NATURAL GAS	18	MMBTU/H	THERE ARE 15 CARBOTTOM FURNACES BEING INSTALLED THAT ARE RATED AT 18 MILLION BTU/HR EACH.
*SC-0142	*SC-0142-Process 3	PITCH IMPREGNATION/PREHEATER	19.6	NATURAL GAS	12	MMBTU/H	
*SC-0142	*SC-0142-Process 4	PITCH IMPREGNATION (AUTOCLAVE/SPRAY COOLER/COOLING BATH)	99.999		0		
*SC-0142	*SC-0142-Process 5	GRAPHITIZING FURNACES	99.999		0		10 ELECTRICALLY POWERED GRAPHITIZING FURNACES
*AK-0076	*AK-0076-Process 1	Combustion of Fuel Gas	16.150	Fuel Gas	7520	kW	7.52 MW with Dry Low NOx and SoLoNOx Technology burning natural gas on the North Slope of Alaska, north of the Artic Circle
*AK-0076	*AK-0076-Process 2	Combustion of Diesel	16.290	ULSD	7520	kW	Burning ULSD in 7.52 MW turbine
*AK-0076	*AK-0076-Process 3	Combustion of Solid Waste	21.100	Wastes	130	lb/hr	Camp Incinerator
*AK-0076	*AK-0076-Process 4	Combustion of Diesel by ICEs	17.110	ULSD	1750	kW	Diesel-fired generators
*AK-0076	*AK-0076-Process 5	Combustion (Flares)	19.390	Fuel Gas	35	MMscf/yr	
*AK-0076	*AK-0076-Process 6	Combustion of Diesel by Boilers	12.220	ULSD	6	MMBtu/hr	
*MN-0085	*MN-0085-Process 1	INDURATING FURNACE	90.031	NATURAL GAS	542	MMBTU/H	THE INDURATING FURNACE INCLUDES BOTH THE FUNANCE HOOD EXHAUST AND THE FURNACE WASTE GAS PROCCESSES. THE NOX AND CO2E BACT LIMITS APPLY TO THE INDURATING FURNACE AS A WHOLE. THE FURNACE HOOD EXHAUST AND FURNACE WASTE GAS HAVE DIFFERENT BACT LIMITS FOR PM, PM10, PM2.5, PB, F, CO, SO2 AND VOCS. THESE LIMITS APPLY SEPARATELY TO THE INDIVIDUAL PROCESSES.

	Emissions Information																		
					Emission Limit 1			Emission Limit 2:			Standard Emission Limit:								
RBLC ID:	Process ID	Pollutant Name	Control Method Code	Control Method Description:	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Case-by-Case Basis:	Other Applicable Requirements	Did factors, other then air pollution technology considerations influence the BACT decisions?	Compliance Verified	Cost Verified (Y/N)?	Pollutants/ Compliance Notes
*IA-0105	*IA-0105-Process 1	Carbon Dioxide	P	good combustion practices	117	LB/MMBTU	ROLLING 30 DAY AVERAGE	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Carbon Dioxide	P	good operational practices	1.26	TONS/TON OF AMMON	ROLLING 30 DAY AVERAGE	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Carbon Dioxide	P	good operational practices	1.1	LB/HR	AVERAGE OF 3 STACK TEST RUNS	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Carbon Dioxide	P	good operational practices	165.4	LB/H	AVERAGE OF 3 STACK TEST RUNS	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Carbon Dioxide	P	good combustion practices	117	LB/MMBTU	ROLLING 30 DAY AVERAGE	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Carbon Dioxide	P	work practice/good combustion practices	0			0			0			BACT-PSD		U	Unknown	No	There is no numeric emission limit in the permit.
*IA-0105	*IA-0105-Process 1	Carbon Dioxide	P	good combustion practices	1.55	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Carbon Dioxide	P	good combustion practices	1.55	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Carbon Dioxide	P	good combustion practices	117	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	0			0			BACT-PSD		U	Unknown	No	
*SC-0142	*SC-0142-Process 1	Carbon Dioxide		GOOD COMBUSTION PRACTICES, ANNUAL TUNE UP, LOW NOX BURNERS	3093	T/YR (CO2E)		0			0			BACT-PSD				No	
*SC-0142	*SC-0142-Process 2	Carbon Dioxide		THERMAL OXIDIZER, LOW NOX BURNERS, GOOD COMBUSTION PRACTICES, ANNUAL TUNE-UP, PROCESS	200009	T/YR (CO2E)		0			0			BACT-PSD				No	
*SC-0142	*SC-0142-Process 3	Carbon Dioxide		GOOD COMBUSTION PRACTICES, ANNUAL TUNE UP, LOW NOX BURNERS	7424	T/YR (CO2E)		0			0			BACT-PSD				No	
*SC-0142	*SC-0142-Process 4	Carbon Dioxide		THERMAL OXIDIZER ONLY CONTROLS VOCS	8973	T/YR (CO2E)		0			0			BACT-PSD				No	
*SC-0142	*SC-0142-Process 5	Carbon Dioxide		WET SCRUBBER, PROCESS OPTIMIZATION	32852	T/YR (CO2E)		0			0			BACT-PSD				No	
*AK-0076	*AK-0076-Process 1	Carbon Dioxide	N	DLN with inlet heating and good combustion practices	0			0			0			BACT-PSD		U	Unknown	No	
*AK-0076	*AK-0076-Process 2	Carbon Dioxide	N	DLN with inlet air heating, good combustion practices, and waste heat recovery	0			0			0			BACT-PSD		U	Unknown	No	
*AK-0076	*AK-0076-Process 3	Carbon Dioxide	N	Good Combustion Practices	0			0			0			BACT-PSD		U	Unknown	No	
*AK-0076	*AK-0076-Process 4	Carbon Dioxide	N	Good Combustion Practices and 40 CFR 60 Subpart IIII requirements	0			0			0			BACT-PSD		U	Unknown	No	
*AK-0076	*AK-0076-Process 5	Carbon Dioxide	N	Good Combustion Practices	0			0			0			BACT-PSD		U	Unknown	No	
*AK-0076	*AK-0076-Process 6	Carbon Dioxide	N	Good Combustion Practices	0			0			0			BACT-PSD		U	Unknown	No	
*MN-0085	*MN-0085-Process 1	Carbon Dioxide	N		710000	TON/YR	12-MONTH ROLLING SUM	0			0			BACT-PSD		N	No	No	COMPLIANCE VERIFIED THROUGH NATURAL GAS USAGE AND VENDOR INFORMATION

	Permit Information												
RBLC ID:	**Corporate/ Company Name**	**Facility Name**	**State**	**EPA Region**	**Permit Number**	**SIC Code**	**NAICS Code**	**Application Accepted Received Date**	**Permit Issuance Date**	**Permit Type**	**Permit URL**	**Facility Description:**	**Permit Notes**
SC-0113	PYRAMAX CERAMICS, LLC	PYRAMAX CERAMICS, LLC	SC	4	0160-0023	3295	327992	09/16/2011 ACT	02/08/2012 ACT	A: New/Greenfield Facility		PYRAMAX CERAMICS PLANS TO CONSTRUCT A MANUFACTURING FACILITY FOR THE PRODUCTION OF PROPPANT BEADS FOR USE IN THE OIL AND GAS INDUSTRY. THE MAJOR RAW MATERIAL IS CLAY. THE CLAY IS MIXED WITH CHEMICALS AND THEN FIRED IN A KILN TO PRODUCE CERAMIC BEADS. INITIAL CONSTRUCTION PERMIT FOR A GREENFIELD FACILITY.	INITIAL CONSTRUCTION PERMIT FOR A GREENFIELD FACILITY.
SC-0114	PYRAMAX CERAMICS, LLC	PYRAMAX CERAMICS, LLC	SC	5	0160-0024	3296	327993	09/16/2011 ACT	02/08/2012 ACT	A: New/Greenfield Facility		PYRAMAX CERAMICS PLANS TO CONSTRUCT A MANUFACTURING FACILITY FOR THE PRODUCTION OF PROPPANT BEADS FOR USE IN THE OIL AND GAS INDUSTRY. THE MAJOR RAW MATERIAL IS CLAY. THE CLAY IS MIXED WITH CHEMICALS AND THEN FIRED IN A KILN TO PRODUCE CERAMIC BEADS. INITIAL CONSTRUCTION PERMIT FOR A GREENFIELD FACILITY.	INITIAL CONSTRUCTION PERMIT FOR A GREENFIELD FACILITY.
SC-0115	PYRAMAX CERAMICS, LLC	PYRAMAX CERAMICS, LLC	SC	6	0160-0025	3297	327994	09/16/2011 ACT	02/08/2012 ACT	A: New/Greenfield Facility		PYRAMAX CERAMICS PLANS TO CONSTRUCT A MANUFACTURING FACILITY FOR THE PRODUCTION OF PROPPANT BEADS FOR USE IN THE OIL AND GAS INDUSTRY. THE MAJOR RAW MATERIAL IS CLAY. THE CLAY IS MIXED WITH CHEMICALS AND THEN FIRED IN A KILN TO PRODUCE CERAMIC BEADS. INITIAL CONSTRUCTION PERMIT FOR A GREENFIELD FACILITY.	INITIAL CONSTRUCTION PERMIT FOR A GREENFIELD FACILITY.
IA-0101	INTERSTATE POWER & LIGHT	OTTUMWA GENERATING STATION	IA	7	78-A-019-P10	4911	221112	05/20/2011 ACT	01/12/2012 ACT	C: Modify process at existing facility	https://aqbweb.iowadnr.gov/psd/9007001/PSD_PN_11-219/78A019P10_boiler.pdf	Electric Utility	This project was to add controls for PM, SO2 and Hg. It resulted in an increase in hours and was major for only CO2e and CO.
IA-0102	INTERSTATE POWER & LIGHT	OTTUMWA GENERATING STATION	IA	8	78-A-019-P11	4912	221113	05/20/2011 ACT	01/12/2012 ACT	C: Modify process at existing facility	https://aqbweb.iowadnr.gov/psd/9007001/PSD_PN_11-219/78A019P10_boiler.pdf	Electric Utility	This project was to add controls for PM, SO2 and Hg. It resulted in an increase in hours and was major for only CO2e and CO.
*MN-0084	UNITED STATES STEEL CORP	U.S. STEEL CORP - KEETAC	MN	5	13700063-004	1011	212210		12/06/2011 ACT	A: New/Greenfield Facility		AFFECTED BOUNDARY (CLASS 1 OR INTERNATIONAL BORDER) AREAS WITHIN 250 KM OF SOURCE: BOUNDARY WATERS CANOE AREA WILDERNESS; 70 KM. RAINBOW LAKES WILDERNESS; 163 KM. VOYAGERS NATIONAL PARK; 103 KM	AFFECTED BOUNDARY (CLASS 1 OR INTERNATIONAL BORDER) AREAS WITHIN 250 KM OF SOURCE: BOUNDARY WATERS CANOE AREA WILDERNESS; 70 KM. RAINBOW LAKES WILDERNESS; 163 KM. VOYAGERS NATIONAL PARK; 103 KM
*FL-0330		PORT DOLPHIN ENERGY LLC	FL	4	DPA-EPA-R4001	4923	213112		12/01/2011 ACT	A: New/Greenfield Facility		Port Dolphin is a deepwater port designed to moor liquefied natural gas shuttle and regasification vessels 28 miles off the cost of Florida.	
*FL-0331		PORT DOLPHIN ENERGY LLC	FL	5	DPA-EPA-R4002	4924	213113		12/01/2011 ACT	A: New/Greenfield Facility		Port Dolphin is a deepwater port designed to moor liquefied natural gas shuttle and regasification vessels 28 miles off the cost of Florida.	
*FL-0332		PORT DOLPHIN ENERGY LLC	FL	6	DPA-EPA-R4003	4925	213114		12/01/2011 ACT	A: New/Greenfield Facility		Port Dolphin is a deepwater port designed to moor liquefied natural gas shuttle and regasification vessels 28 miles off the cost of Florida.	
GA-0143	JM HUBER CORP	HUBER ENGINEERED WOODS, LLC	GA	4	2493-157-0014-V-02-3	2493	321219		11/10/2011 ACT	A: New/Greenfield Facility			
GA-0144	JM HUBER CORP	HUBER ENGINEERED WOODS, LLC	GA	5	2493-157-0014-V-02-4	2494	321220		11/10/2011 ACT	A: New/Greenfield Facility			
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	IN	5	153-29394-00005	4911	221112	06/25/2010 ACT	11/10/2011 ACT	A: New/Greenfield Facility	HTTP://PERMITS.AIR.IDEM.IN.GOV/29394F.PDF	STATIONARY ELECTRIC POWER GENERATING PLANT	
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	IN	5	153-29394-00005	4911	221112	06/25/2010 ACT	11/10/2011 ACT	A: New/Greenfield Facility	HTTP://PERMITS.AIR.IDEM.IN.GOV/29394F.PDF	STATIONARY ELECTRIC POWER GENERATING PLANT	

RBLC ID:	Process ID	Process Name	Process Type	Primary Fuel	Throughput Value	Throughput Unit	Process Notes
SC-0113	SC-0113-Process 1	PELLETIZER	90.009	NATURAL GAS	75	MMBTU/H	THE CONSTRUCTION PERMIT AUTHORIZES THE CONSTRUCTION OF FOUR (4) IDENTICAL PROCESS LINES. THIS PROCESS AND POLLUTANT INFORMATION IS FOR ONE SINGLE PROCESS LINE.
SC-0114	SC-0114-Process 2	CALCINING/SINTERING KILN	90.008	NATURAL GAS	56.8	MMBTU/H	THE CONSTRUCTION PERMIT AUTHORIZES THE CONSTRUCTION OF FOUR (4) IDENTICAL PROCESS LINES. THIS PROCESS AND POLLUTANT INFORMATION IS FOR ONE SINGLE PROCESS LINE.
SC-0115	SC-0115-Process 3	BOILERS	13.310	NATURAL GAS	5	MMBTU/H	THE CONSTRUCTION PERMIT AUTHORIZES THE CONSTRUCTION OF TWO (2) IDENTICAL BOILERS. THIS PROCESS AND POLLUTANT INFORMATION IS FOR ONE SINGLE BOILER.
IA-0101	IA-0101-Process 1	Boiler #1	11.110	PRB Coal	8669	MMBTU/H	
IA-0102	IA-0102-Process 2	Boiler #1	11.110	PRB Coal	8669	MMBTU/H	
*MN-0084	*MN-0084-Process 1	GRATE KILN - DOWN DRAFT DRYING ZONE 1	90.031	BIOMASS & NATURAL GAS	450	T/PELLETS/H	COAL AND FUELL OIL FOR BACKUP
*FL-0330	*FL-0330-Process 1	Boilers (4 - 278 mmbtu/hr each)	11.310	natural gas	0		
*FL-0331	*FL-0331-Process 2	Power Generator Engines (3)	11.310	natural gas	0		2 - 11,400 kW dual fuel Wartsila engines and 1 - 5700 kW dual fue Wartsila engine.
*FL-0332	*FL-0332-Process 3	Fugitive GHG emissions	99.999		0		Process Piping fugitives
GA-0143	GA-0143-Process 1	WELLONS FURNACE	12.120	WOOD WASTE	150	MMBTU/H	BACT FOR THE FURNANCE/DRYER EXHAUST AS A SINGLE EMISSION SOURCE, SINCE THESE PROCESSES SHARE AIRFLOWS AND EXHAUST THROUGH A COMMON MANIFOLD
GA-0144	GA-0144-Process 2	DRYER SYSTEM	12.120	WOOD WASTE	50	ODT/H	BACT FOR THE FURNANCE/DRYER EXHAUST IS EVALUATED AS A SIGNEL EMISSION SOURCE, SINCE THESE PROCESSES SHARE AIRFLOWS AND EXHAUST THROUGH A COMMON MANIFOLD
IN-0135	IN-0135-Process 1	4-STROKE LEAN BURN COAL BED METHANE (CBM)-FIRED RECIPROCATING INTERNAL COMUBSTION ENGINES (RICE)	17.150	COAL BED METHANE	4601	BRAKE HORSEPOWER	THERE ARE 8 OF THESES PROCESSES
IN-0135	IN-0135-Process 2	COAL BED METHANE CBM DEHYDRATOR UNITS (CBM-FIRED REBOILER AND FLASH TANK)	19.900	COAL BED METHANE	0.5	MMBTU/H	THERE ARE TWO OF THESE PROCESSES

	Emissions Information																		
					Emission Limit 1			Emission Limit 2:			Standard Emission Limit:								
RBLC ID:	Process ID	Pollutant Name	Control Method Code	Control Method Description:	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Case-by-Case Basis:	Other Applicable Requirements	Did factors, other then air pollution technology considerations influence the BACT decisions?	Compliance Verified	Cost Verified (Y/N)?	Pollutants/ Compliance Notes
SC-0113	SC-0113-Process 1	Carbon Dioxide	P	CONTROL TECHNOLOGY FOR CO2E: ENERGY EFFICIENT DESIGN AND OPERATION, WASTE HEAT RECOVERY DESIGN, NATURAL GAS/PROPANE.	0			0			0			BACT-PSD		N	No	No	BACT EMISSION LIMIT FOR CO2E = 44,446 TPY (12-MONTH ROLLING SUM). SOURCE TEST EVERY TWO YEARS FOR CO2. CALCULATED EMISSIONS FROM OTHER POLLUTANTS ADDED TO CO2 EMISSIONS ESTABLISHED BY SOURCE TEST TO ARRIVE AT CO2E EMISSIONS.
SC-0114	SC-0114-Process 2	Carbon Dioxide	P	CONTROL METHOD FOR CO2E: ENERGY EFFICIENT DESIGN AND OPERATION, WASTE HEAT RECOVERY DESIGN, NATURAL GAS/PROPANE.	0			0			0			BACT-PSD		N	No	No	BACT EMISSION LIMIT FOR CO2E = 0.218 LB/TON. SOURCE TEST EVERY TWO YEARS FOR CO2. CALCULATED EMISSIONS FROM OTHER POLLUTANTS ADDED TO CO2 EMISSIONS ESTABLISHED BY SOURCE TEST TO ARRIVE AT CO2E EMISSIONS.
SC-0115	SC-0115-Process 3	Carbon Dioxide	A	CONTROL METHOD FOR CO2E: GOOD DESIGN AND COMBUSTION PRACTICES.	0			0			0			BACT-PSD		N	No	No	RECORD TYPE AND QUANTITY OF FUEL CONSUMED.
IA-0101	IA-0101-Process 1	Carbon Dioxide	N	Good Combustion Practices	2927.1	LB/MWH (NET)	30-DAY ROLLING AVERAGE	0			0			BACT-PSD		U	Unknown	No	
IA-0102	IA-0102-Process 2	Carbon Dioxide Equivalent (CO2e)	P	Good Combustion Practices	8000325	T/YR	ROLLING 12 MONTH TOTAL	0			0			BACT-PSD		U	Unknown	No	
*MN-0084	*MN-0084-Process 1	Carbon Dioxide	P	FUEL EFFICIENTY VIA HEAT RECOVERY FROM PELLET COOLERS. ALSO, USE OF A PRIMARY FUEL MIX OF 50% BIOMASS/50% NATURAL GAS.	114000	T FUEL/CO 2/YR	12- MO ROLLING SUM	186400	T/YR CO2-E	12- MO ROLLING SUM	0			BACT-PSD		N	Unknown	No	CARBON DIOXIDE EQUIVALENT COMPLICANCE DETERMINED BY FURL AND PROCESS ADDITIVES SAMPLING, TRACKING AND CALCULATION. FUEL CO2/YR LIMIT IS ON CO2 FROM FUEL ONLY. ALSO, THERE IS A COAL USE LIMIT: 26,100 T COAL/YR BASED ON 12-MO ROLLING SUM.
*FL-0330	*FL-0330-Process 1	Carbon Dioxide	P	tuning, optimization, instrumentation and controls, insulation, and turbulent flow.	117	LB/MMB TU	8-HOUR ROLLING AVERAGE	0			0			BACT-PSD		U	Unknown	No	Emission limit if for CO2-equivalent (CO2e)
*FL-0331	*FL-0331-Process 2	Carbon Dioxide	P	use of efficient engine design and use of primarily natural gas	181	G/KW-H	8-HOUR ROLLING AVERAGE	253	G/KW-H	8-HOUR ROLLING AVERAGE	0			BACT-PSD		U	Unknown	No	Emission limit 1 - natural gas; Emission limit 2 - low sulfur fuel oil
*FL-0332	*FL-0332-Process 3	Carbon Dioxide	P	a gas and leak detection system will be used.	0			0			0			BACT-PSD		U	Unknown	No	
GA-0143	GA-0143-Process 1	Carbon Dioxide	P	THE COMBUSTION OF BIOMASS AND THE USE OF GOOD COMBUSTION/OPERATING PRACTICES TO CONTROL GHGS.	0		YEAR ROUND	0			0			BACT-PSD	SIP , OPERATING PERMIT	Y	Unknown	No	EMISSION LIMIT 1: FIRE BIOGENIC CARBON STOCK. POLLUTANT NAME: CO2E: (CO2, CH4)
GA-0144	GA-0144-Process 2	Carbon Dioxide	P	THE COMBUSTION OF BIOMASS AND THE USE OF GOOD COMBUSTION/OPERATING PRACTICES TO CONTROL GHGS.	0		YEAR ROUND	0			0			BACT-PSD	SIP , OPERATING PERMIT	Y	Unknown	No	EMISSION LIMIT 1: FIRE BIOGENIC CARBON STOCK POLLUTANT NAME: CO2E (CO2, CH4)
IN-0135	IN-0135-Process 1	Carbon Dioxide	P	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	1100	LB/MW-H	3 HOURS	16030	T/12 CONSEC MONTHS	12 CONSECUTI VE MONTH PERIOD	0			OTHER CASE-BY-CASE	N/A	U	Unknown	No	PERFORM REGULAR MAINTENANCE USING THE MANUFACTURER'S OR OPERATOR'S MAINTENANCE PROCEDURES; KEEP RECORDS OF ANY MAINTENANCE THAT WOULD HAVE A SIGNIFICANT EFFECT ON EMISSIONS; THE RECORDS MAY BE KEPT IN ELECTRONIC FORMAT; AND KEEP A COPY OF EITHER THE MANUFACTURER'S OR THE OPERATOR'S MAINTENANCE PROCEDURES. PSD BACT
IN-0135	IN-0135-Process 2	Carbon Dioxide	P	PROPER MAINTENANCE	59.36	LB/H	HOURLY	260	T/12 CONSEC MONTHS	12 CONSECUTI VE MONTH PERIOD	0			OTHER CASE-BY-CASE	N/A	U	Unknown	No	PSD BACT

	Permit Information												
RBLC ID:	Corporate/ Company Name	Facility Name	State	EPA Region	Permit Number	SIC Code	NAICS Code	Application Accepted Received Date	Permit Issuance Date	Permit Type	Permit URL	Facility Description:	Permit Notes
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	IN	5	153-29394-00005	4911	221112	06/25/2010 ACT	11/10/2011 ACT	A: New/Greenfield Facility	HTTP://PERMITS.AIR.IDEM.IN.GOV/29394F.PDF	STATIONARY ELECTRIC POWER GENERATING PLANT	
*FL-0328	ENI U.S. OPERATING COMPANY, INC.	ENI - HOLY CROSS DRILLING PROJECT	FL	4	OCS-EPA-R4007	1382	211112		10/27/2011 ACT	A: New/Greenfield Facility	http://www.epa.gov/region4/air/permits/OCSPermits/EniOCS.html	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: th initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will last up to two years, and based on applicable permitting regulations, is a "temporary source" for PSD permitting purposes.	
*FL-0328	ENI U.S. OPERATING COMPANY, INC.	ENI - HOLY CROSS DRILLING PROJECT	FL	4	OCS-EPA-R4007	1382	211112		10/27/2011 ACT	A: New/Greenfield Facility	http://www.epa.gov/region4/air/permits/OCSPermits/EniOCS.html	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: th initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will last up to two years, and based on applicable permitting regulations, is a "temporary source" for PSD permitting	
*FL-0328	ENI U.S. OPERATING COMPANY, INC.	ENI - HOLY CROSS DRILLING PROJECT	FL	4	OCS-EPA-R4007	1382	211112		10/27/2011 ACT	A: New/Greenfield Facility	http://www.epa.gov/region4/air/permits/OCSPermits/EniOCS.html	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: th initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will last up to two years, and based on applicable permitting regulations, is a "temporary source" for PSD permitting purposes.	
*FL-0328	ENI U.S. OPERATING COMPANY, INC.	ENI - HOLY CROSS DRILLING PROJECT	FL	4	OCS-EPA-R4007	1382	211112		10/27/2011 ACT	A: New/Greenfield Facility	http://www.epa.gov/region4/air/permits/OCSPermits/EniOCS.html	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: th initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will last up to two years, and based on applicable permitting regulations, is a "temporary source" for PSD permitting purposes.	
*FL-0328	ENI U.S. OPERATING COMPANY, INC.	ENI - HOLY CROSS DRILLING PROJECT	FL	4	OCS-EPA-R4007	1382	211112		10/27/2011 ACT	A: New/Greenfield Facility	http://www.epa.gov/region4/air/permits/OCSPermits/EniOCS.html	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: th initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will last up to two years, and based on applicable permitting regulations, is a "temporary source" for PSD permitting purposes.	
*FL-0328	ENI U.S. OPERATING COMPANY, INC.	ENI - HOLY CROSS DRILLING PROJECT	FL	4	OCS-EPA-R4007	1382	211112		10/27/2011 ACT	A: New/Greenfield Facility	http://www.epa.gov/region4/air/permits/OCSPermits/EniOCS.html	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: th initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will last up to two years, and based on applicable permitting regulations, is a "temporary source" for PSD permitting purposes.	

	Process Information						
					Throughput		Process Notes
RBLC ID:	Process ID	Process Name	Process Type	Primary Fuel	Value	Unit	
IN-0135	IN-0135-Process 3	COAL BED METHANE-FIRED STANDBY FLARE W/PROPANE-FIRED PILOT	19.390	COAL BED METHANE	25	MMBTU/H	WITH 0.8 MMBTU/HR FOR THE PILOT WITH PROPANE AS THE PILOT'S PRIMARY FUEL
*FL-0328	*FL-0328-Process 1	Main Propulsion Engines	17.110	Diesel	0		Wärtsilä Vasa 18V32 LNE and Wärtsilä Vasa 12V32 LNE model engines
*FL-0328	*FL-0328-Process 2	Crane Engines (units 1 and 2)	17.110	Diesel	0		Caterpillar 3408 - 1997 model year engines
*FL-0328	*FL-0328-Process 3	Crane Engines (units 3 and 4)	17.110	Diesel	0		Caterpillar 3406 - 2008 model year engines
*FL-0328	*FL-0328-Process 4	Emergency Engine	17.110	Diesel	0		MAN D-2842 LE model engine
*FL-0328	*FL-0328-Process 5	Emergency Fire Pump Engine	17.110	Diesel	0		Detroit 8V-92 TA model engine
*FL-0328	*FL-0328-Process 6	Boiler	13.220	Diesel	9.6	mmBTU/h	Aalborg PH-12t/H model boiler

	Emissions Information																		
					Emission Limit 1			Emission Limit 2:			Standard Emission Limit:								
RBLC ID:	Process ID	Pollutant Name	Control Method Code	Control Method Description:	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Case-by-Case Basis:	Other Applicable Requirements	Did factors, other then air pollution technology considerations influence the BACT decisions?	Compliance Verified	Cost Verified (Y/N)?	Pollutants/ Compliance Notes
IN-0135	IN-0135-Process 3	Carbon Dioxide	P	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	3235	LB/MW-H		4852	T/12 CONSEC MONTHS	12 MONTH CONSECUTIVE PERIOD	0			OTHER CASE-BY-CASE	N/A	U	Unknown	No	PERFORM REGULAR MAINTENANCE USING THE MANUFACTURER'S OR OPERATOR'S MAINTENANCE PROCEDURES; KEEP RECORDS OF ANY MAINTENANCE THAT WOULD HAVE A SIGNIFICANT EFFECT ON EMISSIONS; THE RECORDS MAY BE KEPT IN ELECTRONIC FORMAT; AND KEEP A COPY OF EITHER THE MANUFACTURER'S OR THE OPERATOR'S MAINTENANCE PROCEDURES PSD BACT
*FL-0328	*FL-0328-Process 1	Carbon Dioxide	P	Use of good combustion practices based on the current manufacturer's specifications for these engines, and additional enhanced work practice standards including an engine performance management system and the Diesel Engines with Turbochargers (DEWT) measurement system.	700	G/KW-H	24-HOUR ROLLING	0			0			BACT-PSD		U	Unknown	No	as CO2-equivalent
*FL-0328	*FL-0328-Process 2	Carbon Dioxide	P	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturer's specifications for this engine.	722	TONS PER YEAR	12-MONTH ROLLING	0			0			BACT-PSD		U	Unknown	No	CO2-equivalent (CO2e)
*FL-0328	*FL-0328-Process 3	Carbon Dioxide	N	Use of good combustion practices, based on the current manufacturer's specifications for this engine	687	TONS PER YEAR	12-MONTH ROLLING	0			0			BACT-PSD		U	Unknown	No	CO2-equivalent (CO2e)
*FL-0328	*FL-0328-Process 4	Carbon Dioxide	N	Use of good combustion practices, based on the current manufacturer's specifications for this engine	14.6	TONS PER YEAR	12-MONTH ROLLING	0			0			BACT-PSD		U	Unknown	No	CO2-equivalent (CO2e)
*FL-0328	*FL-0328-Process 5	Carbon Dioxide	N	Use of good combustion practices, based on the current manufacturer's specifications for this engine	2.4	TONS PER YEAR	12-MONTH ROLLING	0			0			BACT-PSD		U	Unknown	No	CO2-equivalent (CO2e)
*FL-0328	*FL-0328-Process 6	Carbon Dioxide	N	Use of good combustion and maintenance practices, based on the current manufacturer's specifications for this boiler.	565	TONS PER YEAR	12-MONTH ROLLING	0			0			BACT-PSD		U	Unknown	No	CO2-equivalent (CO2e)

RBLC ID:	Permit Information												
	Corporate/ Company Name	Facility Name	State	EPA Region	Permit Number	SIC Code	NAICS Code	Application Accepted Received Date	Permit Issuance Date	Permit Type	Permit URL	Facility Description:	Permit Notes
LA-0254	ENTERGY LOUISIANA LLC	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	6	PSD-LA-752	4911	221112	09/14/2010 ACT	08/16/2011 ACT	B: Add new process to existing facility		1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS BACT FOR GREENHOUSE GASES (CO2E) FROM THE COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B) IS OPERATING PROPERLY AND PERFORMING NECESSARY ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT TO MAINTAIN THE GROSS HEAT RATE AT OR BELOW 7630 BTU/KW-HR (HHV) (ANNUAL AVERAGE).
LA-0254	ENTERGY LOUISIANA LLC	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	6	PSD-LA-752	4911	221112	09/14/2010 ACT	08/16/2011 ACT	B: Add new process to existing facility		1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS BACT FOR GREENHOUSE GASES (CO2E) FROM THE COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B) IS OPERATING PROPERLY AND PERFORMING NECESSARY ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT TO MAINTAIN THE GROSS HEAT RATE AT OR BELOW 7630 BTU/KW-HR (HHV) (ANNUAL AVERAGE).
LA-0254	ENTERGY LOUISIANA LLC	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	6	PSD-LA-752	4911	221112	09/14/2010 ACT	08/16/2011 ACT	B: Add new process to existing facility		1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS BACT FOR GREENHOUSE GASES (CO2E) FROM THE COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B) IS OPERATING PROPERLY AND PERFORMING NECESSARY ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT TO MAINTAIN THE GROSS HEAT RATE AT OR BELOW 7630 BTU/KW-HR (HHV) (ANNUAL AVERAGE).
LA-0248	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC - NUCOR	DIRECT REDUCTION IRON PLANT	LA	6	PSD-LA-751	3312	331111	10/31/2010 ACT	01/27/2011 ACT	B: Add new process to existing facility		The DRI process reduces the iron oxide content of iron ore pellets into iron metal through direct contact with a reducing gas. The effectiveness of this reduction process is called metallization, and the process equipment will be designed to achieve a metallization rate of at least 92% of the oxides within the ore. The reduction will take place in a countercurrent vertical shaft furnace, where reducing gas passes up through iron oxide pellets, which feed through the furnace by gravity. The major elements of the DRI process include the following: (1) iron oxide preparation; (2) reducing gas preparation; (3) DRI reactor shaft furnace; (4) spent reducing gas preparation for reuse, (5) DRI product handling; and (6) ancillary operations, including a package boiler, two cooling towers, and a flare for emergency situations.	This PSD permit also evaluated BACT for Green House Gases
LA-0248	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC - NUCOR	DIRECT REDUCTION IRON PLANT	LA	6	PSD-LA-751	3312	331111	10/31/2010 ACT	01/27/2011 ACT	B: Add new process to existing facility		The DRI process reduces the iron oxide content of iron ore pellets into iron metal through direct contact with a reducing gas. The effectiveness of this reduction process is called metallization, and the process equipment will be designed to achieve a metallization rate of at least 92% of the oxides within the ore. The reduction will take place in a countercurrent vertical shaft furnace, where reducing gas passes up through iron oxide pellets, which feed through the furnace by gravity. The major elements of the DRI process include the following: (1) iron oxide preparation; (2) reducing gas preparation; (3) DRI reactor shaft furnace; (4) spent reducing gas preparation for reuse, (5) DRI product handling; and (6) ancillary operations, including a package boiler, two cooling towers, and a flare for emergency situations.	This PSD permit also evaluated BACT for Green House Gases

	Process Information						
					Throughput		Process Notes
RBLC ID:	Process ID	Process Name	Process Type	Primary Fuel	Value	Unit	
LA-0254	LA-0254-Process 1	AUXILIARY BOILER (AUX-1)	11.310	NATURAL GAS	338	MMBTU/H	
LA-0254	LA-0254-Process 2	EMERGENCY DIESEL GENERATOR	17.110	DIESEL	1250	HP	
LA-0254	LA-0254-Process 3	EMERGENCY FIRE PUMP	17.210	DIESEL	350	HP	
LA-0248	LA-0248-Process 1	DRI-111 - DRI Unit #1 Acid Gas Absorption Vent	81.290		30624	scfm	Acid gases, primarily hydrogen sulfide and carbon dioxide, are removed from the DRI top gas prior to its use as a fuel in the acid gas absorption unit. This unit is an amine-based absorption scrubber, which selectively dissolves acid gases from the top gas fuel. The amine solution is then regenerated by applying heat in a steam reboiler, which liberates the acid gases from solution. The resulting gas stream is treated for the removal of sulfur compounds prior to being vented.
LA-0248	LA-0248-Process 2	DRI-211 - DRI Unit #1 Acid Gas Absorption Vent	81.290		30624	scfm	Acid gases, primarily hydrogen sulfide and carbon dioxide, are removed from the DRI top gas prior to its use as a fuel in the acid gas absorption unit. This unit is an amine-based absorption scrubber, which selectively dissolves acid gases from the top gas fuel. The amine solution is then regenerated by applying heat in a steam reboiler, which liberates the acid gases from solution. The resulting gas stream is treated for the removal of sulfur compounds prior to being vented.

	Emissions Information				Emission Limit 1			Emission Limit 2:			Standard Emission Limit:								
RBLC ID:	Process ID	Pollutant Name	Control Method Code	Control Method Description:	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Case-by-Case Basis:	Other Applicable Requirements	Did factors, other then air pollution technology considerations influence the BACT decisions?	Compliance Verified	Cost Verified (Y/N)?	Pollutants/ Compliance Notes
LA-0254	LA-0254-Process 1	Carbon Dioxide	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	117	LB/MMBTU		0			117	LB/MMBTU		BACT-PSD	OPERATING PERMIT	U	Unknown	No	
LA-0254	LA-0254-Process 2	Carbon Dioxide	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	163	LB/MMBTU		0			163	LB/MMBTU		BACT-PSD	OPERATING PERMIT	U	Unknown	No	
LA-0254	LA-0254-Process 3	Carbon Dioxide	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	163	LB/MMBTU		0			163	LB/MMBTU		BACT-PSD	OPERATING PERMIT	U	Unknown	No	
LA-0248	LA-0248-Process 1	Sulfur Dioxide (SO2)	A	BACT is selected to be treatment of the acid gas stream through the use of a sulfur redox catalyst, such as the SulfaTreat catalyst bed or LO-CAT Redox process, for the removal of H2S. Nucor will install a redox catalyst on each of the acid gas absorption vents at the DRI facility for the control of sulfur compound emissions.	0.58	LB/H		2.12	T/YR		0			BACT-PSD		N	Unknown	No	The acid gas absorber selectively removes acid gases such as hydrogen sulfide and carbon dioxide from the top gas fuel, prior to combustion at the reformer. The amine-based absorption medium is then regenerated by the application of heat, releasing the absorbed acid gases as a separate gas stream. The efficiency of the DRI process benefits from the removal of these gases, which are no longer heated during combustion. The energy saved from no longer heating inert gases in the top gas fuel is then available for the reforming reaction. An added benefit is the isolation of hydrogen sulfide, which can then be treated more effectively.
LA-0248	LA-0248-Process 2	Sulfur Dioxide (SO2)	N		0.58	LB/H		2.12	T/YR		0			BACT-PSD		N	Unknown	No	The acid gas absorber selectively removes acid gases such as hydrogen sulfide and carbon dioxide from the top gas fuel, prior to combustion at the reformer. The amine-based absorption medium is then regenerated by the application of heat, releasing the absorbed acid gases as a separate gas stream. The efficiency of the DRI process benefits from the removal of these gases, which are no longer heated during combustion. The energy saved from no longer heating inert gases in the top gas fuel is then available for the reforming reaction. An added benefit is the isolation of hydrogen sulfide, which can then be treated more effectively. BACT is selected to be treatment of the acid gas stream through the use of a sulfur redox catalyst, such as the SulfaTreat catalyst bed or LO-CAT Redox process, for the removal of H2S. Nucor will install a redox catalyst on each of the acid gas absorption vents at the DRI facility for the control of sulfur compound emissions.

RBLC ID:	Permit Information												
	Corporate/ Company Name	Facility Name	State	EPA Region	Permit Number	SIC Code	NAICS Code	Application Accepted Received Date	Permit Issuance Date	Permit Type	Permit URL	Facility Description:	Permit Notes
LA-0248	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC - NUCOR	DIRECT REDUCTION IRON PLANT	LA	6	PSD-LA-751	3312	331111	10/31/2010 ACT	01/27/2011 ACT	B: Add new process to existing facility		The DRI process reduces the iron oxide content of iron ore pellets into iron metal through direct contact with a reducing gas. The effectiveness of this reduction process is called metallization, and the process equipment will be designed to achieve a metallization rate of at least 92% of the oxides within the ore. The reduction will take place in a countercurrent vertical shaft furnace, where reducing gas passes up through iron oxide pellets, which feed through the furnace by gravity. The major elements of the DRI process include the following: (1) iron oxide preparation; (2) reducing gas preparation; (3) DRI reactor shaft furnace; (4) spent reducing gas preparation for reuse, (5) DRI product handling; and (6) ancillary operations, including a package boiler, two cooling towers, and a flare for emergency situations.	This PSD permit also evaluated BACT for Green House Gases
LA-0248	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC - NUCOR	DIRECT REDUCTION IRON PLANT	LA	6	PSD-LA-751	3312	331111	10/31/2010 ACT	01/27/2011 ACT	B: Add new process to existing facility		The DRI process reduces the iron oxide content of iron ore pellets into iron metal through direct contact with a reducing gas. The effectiveness of this reduction process is called metallization, and the process equipment will be designed to achieve a metallization rate of at least 92% of the oxides within the ore. The reduction will take place in a countercurrent vertical shaft furnace, where reducing gas passes up through iron oxide pellets, which feed through the furnace by gravity. The major elements of the DRI process include the following: (1) iron oxide preparation; (2) reducing gas preparation; (3) DRI reactor shaft furnace; (4) spent reducing gas preparation for reuse, (5) DRI product handling; and (6) ancillary operations, including a package boiler, two cooling towers, and a flare for emergency situations.	This PSD permit also evaluated BACT for Green House Gases
TX-0550	BASF FINA PETROCHEMICALS LIMITED PARTNERSHIP	BASF FINA NAFTA REGION OLEFINS COMPLEX	TX	6	36644	2869	325131	05/07/2008 ACT	02/10/2010 ACT	A: New/Greenfield Facility		OLEFINS COMPLEX, ETHYLENE CRACKING FACILITY	NO PROCESSES WERE ADDED OR AMENDED HOWEVER CALCULATIONS FOR VARIOUS EPNS WERE REVIEWED AND REVISED BY THE APPLICANT WHEN THE PERMIT WAS EVALUATED FOR RENEWAL. AN EMISSIONS RECALCULATION RESULTED IN ANNUAL CO EMISSIONS INCREASE AT EPNS N-10, N-11, AND N-18 AND A PSD AMENDMENT. CO DECREASED AT EPN N-13 AND VOC INCREASED AT EPNS N-10, N-11, N-19, F-1, AND F-5 AS WELL AS AN INCREASE IN NH3 EMISSIONS AT EPN N-23 THAT DID NOT QUALIFY AS A MAJOR MODIFICATION.
TX-0550	BASF FINA PETROCHEMICALS LIMITED PARTNERSHIP	BASF FINA NAFTA REGION OLEFINS COMPLEX	TX	6	36644	2869	325131	05/07/2008 ACT	02/10/2010 ACT	A: New/Greenfield Facility		OLEFINS COMPLEX, ETHYLENE CRACKING FACILITY	NO PROCESSES WERE ADDED OR AMENDED HOWEVER CALCULATIONS FOR VARIOUS EPNS WERE REVIEWED AND REVISED BY THE APPLICANT WHEN THE PERMIT WAS EVALUATED FOR RENEWAL. AN EMISSIONS RECALCULATION RESULTED IN ANNUAL CO EMISSIONS INCREASE AT EPNS N-10, N-11, AND N-18 AND A PSD AMENDMENT. CO DECREASED AT EPN N-13 AND VOC INCREASED AT EPNS N-10, N-11, N-19, F-1, AND F-5 AS WELL AS AN INCREASE IN NH3 EMISSIONS AT EPN N-23 THAT DID NOT QUALIFY AS A MAJOR MODIFICATION.
TX-0550	BASF FINA PETROCHEMICALS LIMITED PARTNERSHIP	BASF FINA NAFTA REGION OLEFINS COMPLEX	TX	6	36644	2869	325131	05/07/2008 ACT	02/10/2010 ACT	A: New/Greenfield Facility		OLEFINS COMPLEX, ETHYLENE CRACKING FACILITY	NO PROCESSES WERE ADDED OR AMENDED HOWEVER CALCULATIONS FOR VARIOUS EPNS WERE REVIEWED AND REVISED BY THE APPLICANT WHEN THE PERMIT WAS EVALUATED FOR RENEWAL. AN EMISSIONS RECALCULATION RESULTED IN ANNUAL CO EMISSIONS INCREASE AT EPNS N-10, N-11, AND N-18 AND A PSD AMENDMENT. CO DECREASED AT EPN N-13 AND VOC INCREASED AT EPNS N-10, N-11, N-19, F-1, AND F-5 AS WELL AS AN INCREASE IN NH3 EMISSIONS AT EPN N-23 THAT DID NOT QUALIFY AS A MAJOR MODIFICATION.

	Process Information						
					Throughput		Process Notes
RBLC ID:	**Process ID**	**Process Name**	**Process Type**	**Primary Fuel**	**Value**	**Unit**	
LA-0248	LA-0248-Process 3	DRI-108 - DRI Unit #1 Reformer Main Flue Stack	81.200	Iron Ore and Natural Gas	12168	Billion Btu/yr	The Direct Reduction Iron process consists of two main component a Reformer and the DRI reactor. Natural gas passes through special catalyst tubes where the natural gas dissociates into a reducing gas rich in carbon monoxide and hydrogen, which are the primary chemicals used to remove the oxygen from the iron ore. The reducing gas is fed in from the bottom of the DRI Reactor. The gas flows countercurrent to the descending iron ore pellets. At the top of the reactor, the partially spent reducing gas exits and is recompressed, enriched with natural gas, preheated, and transported back to the gas reformer. The reformer reforms the mixture back to 95% hydrogen plus carbon monoxide, which is then ready for re-use by the direct reduction furnace. Some of the reducing gas that has already passed over the iron ore in the DRI reactor (the spent reducing gas is also known as top gas) is mixed with the natural gas that is being combusted in the reformer and is also therefore combusted.
LA-0248	LA-0248-Process 4	DRI-208 - DRI Unit #2 Reformer Main Flue Stack	81.200	Iron ore and Natural Gas	12168	Billion Btu/yr	The Direct Reduction Iron process consists of two main component a Reformer and the DRI reactor. Natural gas passes through special catalyst tubes where the natural gas dissociates into a reducing gas rich in carbon monoxide and hydrogen, which are the primary chemicals used to remove the oxygen from the iron ore. The reducing gas is fed in from the bottom of the DRI Reactor. The gas flows countercurrent to the descending iron ore pellets. At the top of the reactor, the partially spent reducing gas exits and is recompressed, enriched with natural gas, preheated, and transported back to the gas reformer. The reformer reforms the mixture back to 95% hydrogen plus carbon monoxide, which is then ready for re-use by the direct reduction furnace. Some of the reducing gas that has already passed over the iron ore in the DRI reactor (the spent reducing gas is also known as top gas) is mixed with the natural gas that is being combusted in the reformer and is also therefore combusted.
TX-0550	TX-0550-Process 1	N-10, CATALYST REGENERATION EFFLUENT	50.003	METHANE	2100	CFS	THE RACT/BACT/LAER (RBLC) DATABASE WAS SEARCHED FOR THIS FACILITY TYPE. A MARATHON PETROLEUM DETROIT REFINERY CATALYST REGENERATION UNIT AND A BP WEST COAST PRODUCTS CATALYST REGENERATION UNIT USED GOOD COMBUSTION PRACTICES TO MEET BACT. THESE WERE THE ONLY FACILITIES LISTED IN THE RBLC DATABASE FOR THIS FACILITY TYPE. GOOD COMBUSTION PRACTICES ARE USED FOR EPN N-10.THE CATALYST FROM THE ACETYLENE CONVERTER MAIN BEDS, ACETYLENE CONVERTER GUARD BED, METHYL ACETYLENE, PROPADIENE CONVERTERS, C4 DIOLEFIN HYDROGENATION REACTOR AND FIRST STAGE DIOLEFINS REACTOR IS HEATED AND ANY COKE PRESENT ON THE CATALYST IS CONVERTED TO CO OR CO2. SINCE GOOD COMBUSTION PRACTICES ARE GOOD BUSINESS PRACTICE, NO ADDITIONAL CONDITIONS OR MONITORING WERE REQUIRED FOR THIS AMENDMENT.
TX-0550	TX-0550-Process 2	N-11, REACTOR REGENERATION EFFLUENT	50.003	METHANE	5064.83	CFS	THE RACT/BACT/LAER DATABASE WAS SEARCHED FOR THIS FACILITY TYPE AND NO EXACT PROCESS WAS FOUND. THE MSS PROCESS AT N-11 IS SIMILAR TO N-10, THE CATALYST FROM THE DP REACTOR IS HEATED AND ANY COKE PRESENT ON THE CATALYST IS CONVERTED TO CO OR CO2. UNIT USED GOOD COMBUSTION PRACTICES TO MEET BACT SINCE GOOD COMBUSTION PRACTICES ARE GOOD BUSINESS PRACTICE, NO ADDITIONAL CONDITIONS OR MONITORING WERE REQUIRED FOR THIS AMENDMENT.
TX-0550	TX-0550-Process 3	N-18, DECOKING DRUM	50.003	METHANE	26625	LB COKE/CYCLE	THE RACT/BACT/LAER DATABASE WAS SEARCHED FOR THIS FACILITY TYPE AND SIMILAR PROCESSES WERE FOUND BUT THERE WERE NO PROJECT NOTES. THE DECOKING DRUM AND FURNACE TUBES ARE HEATED AND ANY COKE PRESENT ON THE CATALYST IS CONVERTED TO CO OR CO2. UNIT USED GOOD COMBUSTION PRACTICES TO MEET BACT. SINCE GOOD COMBUSTION PRACTICES ARE GOOD BUSINESS PRACTICE, NO ADDITIONAL CONDITIONS OR MONITORING WERE REQUIRED FOR THIS AMENDMENT.

	Emissions Information																		
					Emission Limit 1			Emission Limit 2:			Standard Emission Limit:								
RBLC ID:	Process ID	Pollutant Name	Control Method Code	Control Method Description:	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Case-by-Case Basis:	Other Applicable Requirements	Did factors, other then air pollution technology considerations influence the BACT decisions?	Compliance Verified	Cost Verified (Y/N)?	Pollutants/ Compliance Notes
LA-0248	LA-0248-Process 3	Carbon Dioxide	B	the best available technology for controlling CO2e emissions from the DRI Reformer is good combustion practices, the Acid gas separation system, and Energy integration. BACT shall be good combustion practices, which will be adhered to maintain low levels of fuel consumption by the LNB burners.	11.79	MMBTU/ TON OF DRI		0			11.79	MMBTU/TON OF DRI		BACT-PSD		Y	Yes	No	Due to production rate and product quality variability in any production process, production rates should be inclusive of all production at the facility, both of regular and off-spec materials. Additionally, natural gas is consumed in the DRI process as both a raw material (for the formation of reducing gas) and as a fuel (for heating to reaction temperatures). All sources of natural gas consumption at the Reformer should be included in the analysis. BACT is no more than 13 decatherms of natural gas per tonne of DRI (11.79 MM Btu/ton of DRI). Compliance with the BACT limit shall be determined on the basis of total natural gas consumption, divided by total production (including regular and off-spec DRI product) of the facility on a 12-month rolling average.
LA-0248	LA-0248-Process 4	Carbon Dioxide	B	the best available technology for controlling CO2e emissions from the DRI Reformer is good combustion practices, the Acid gas separation system, and Energy integration. BACT shall be good combustion practices, which will be adhered to maintain low levels of fuel consumption by the LNB burners.	11.79	MMBTU/ TON OF DRI		0			11.79	MMBTU/TON OF DRI		BACT-PSD		Y	Yes	No	Due to production rate and product quality variability in any production process, production rates should be inclusive of all production at the facility, both of regular and off-spec materials. Additionally, natural gas is consumed in the DRI process as both a raw material (for the formation of reducing gas) and as a fuel (for heating to reaction temperatures). All sources of natural gas consumption at the Reformer should be included in the analysis. BACT is no more than 13 decatherms of natural gas per tonne of DRI (11.79 MM Btu/ton of DRI). Compliance with the BACT limit shall be determined on the basis of total natural gas consumption, divided by total production (including regular and off-spec DRI product) of the facility on a 12-month rolling average.
TX-0550	TX-0550-Process 1	Carbon Dioxide	N		0		SEE NOTE	0			0			BACT-PSD		U	Unknown	No	NO EMISSION LIMITS AVAILABLE
TX-0550	TX-0550-Process 2	Carbon Dioxide	N		0		SEE NOTE	0			0			BACT-PSD		U	Unknown	No	NO EMISSION LIMITS AVAILABLE
TX-0550	TX-0550-Process 3	Carbon Dioxide	N		0		SEE NOTE	0			0			BACT-PSD		U	Unknown	No	NO EMISSION LIMITS AVAILABLE

	Permit Information												
RBLC ID:	**Corporate/ Company Name**	**Facility Name**	**State**	**EPA Region**	**Permit Number**	**SIC Code**	**NAICS Code**	**Application Accepted Received Date**	**Permit Issuance Date**	**Permit Type**	**Permit URL**	**Facility Description:**	**Permit Notes**
OK-0135	PRYOR PLANT CHEMICAL COMPANY	PRYOR PLANT CHEMICAL	OK	6	2008-100-C PSD	2873	325311	03/27/2008 ACT	02/23/2009 ACT	C: Modify process at existing facility			PRYOR PLANT CHEMICAL COMPANY (PPCC) SUBMITTED AN APPLICATION DATED MARCH 27, 2008 TO AIR QUALITY DIVISION (AQD) WITH THE REQUIRED FEE OF $2,000 FOR A CONSTRUCTION PERMIT TO PLACE INTO OPERATION A SYNTHETIC FERTILIZER MANUFACTURING PLANT (SIC 2873) THAT HAS BEEN SHUT DOWN FOR APPROXIMATELY TEN YEARS. RATHER THAN ATTEMPT TO RECONCILE EXISTING PERMITS WITH CHANGES THAT MAY RESULT FROM RE-STARTING A PLANT THAT HAS BEEN INACTIVE FOR TEN YEARS TO EVALUATE WHERE SIGNIFICANT MODIFICATIONS ARE OCCURRING, A DECISION TO SIMPLIFY THE PERMITTING PROCESS WAS MADE BY THE APPLICANT AND ACCEPTED BY AQD. A FULL PSD (PREVENTION OF SIGNIFICANT DETERIORATION) ANALYSIS HAS BEEN COMPLETED FOR THIS PERMIT ISSUANCE. IN ADDITION, EVALUATION OF COMPLIANCE ASSURANCE MONITORING (CAM) IS REQUIRED.
LA-0148	RED RIVER ENVIRONMENTAL PRODUCTS LLC	ACTIVATED CARBON FACILITY	LA	6	PSD-LA-727	2819	325998	08/02/2007 ACT	05/28/2008 ACT	A: New/Greenfield Facility		THE FACILITY WILL USE COAL AS A FEEDSTOCK TO MANUFACTURE ROUGHLY 350 MILLION POUNDS OF ACTIVATED CARBON (AC) PER YEAR. COMPANY CHANGED NAMES TO ADA CARBON SOLUTIONS (RED RIVER), LLC, EFFECTIVE JANUARY 18, 2011.	PSD-LA-727(M-1), ISSUED DECEMBER 22, 2011, CLARIFIED THAT THE SNCR EQUIPMENT USED TO CONTROL NOX EMISSIONS FROM THE MULTI-HEARTH FURNACES IS NOT REQUIRED TO BE UTILIZED AT ALL TIMES IF THE 77.3 LB/HR BACT LIMIT CAN BE MET USING COMBUSTION CONTROLS.
AL-0231	NUCOR CORPORATION	NUCOR DECATUR LLC	AL	4	712-0037	3312	331111	02/02/2007 ACT	06/12/2007 ACT	Both B: (Add new process to existing facility) &C: (Modify process at existing facility)		THE FACILITY PRODUCES STEEL COILS PRIMARILY FROM STEEL SCRAP USING THE ELECTRIC ARC FURNACE (EAF) PROCESS.	FACILITYWIDE EMISSIONS CONTINUED: PB - 1.5 T/YR
TX-0481	AIR PRODUCTS LP	AIR PRODUCTS BAYTOWN I I	TX	6	PSD-TX-1044 / 35873	492	486210	03/31/2004 ACT	11/02/2004 ACT	U: Unspecified		THIS FACILITY GETS RAW SYNTHESIS GAS FROM EXXON¿S SYNTHESIS GAS MANUFACTURING UNIT. THE RAW SYNGAS STREAM FROM THE EXXON PLANT, CONSISTING OF CO2, CO, H2, H2S, COS, HCN, NH3 AND METHANE, IS PIPED TO THE AIR PRODUCTS PLANT WHERE THE ACID GASES AND AMMONIA WILL BE REMOVED BY AIR PRODUCTS¿ RECTISOL UNIT. THE PRODUCTS PRODUCED INCLUDE CO, AND TWO PURE SYNTHESES GAS PRODUCTS. THESE PRODUCTS ARE DISTRIBUTED TO CUSTOMERS VIA PIPELINES. AN IMPURE SYNGAS IS ALSO PRODUCED AND USED OFFSITE AS FUEL. THE NEW PROCESS WILL CONVERT A PORTION OF THE SYNGAS TO HYDROGEN. THE HYDROGEN WILL BE PURIFIED AND DISTRIBUTED TO CUSTOMERS.	AIR PRODUCTS REQUESTED AN AMENDMENT TO AUTHORIZE THE ADDITION OF A HYDROGEN PURIFICATION SYSTEM TO THEIR SYN GAS PRODUCTION FACILITY. THE REQUESTED ADDITIONS INCLUDED: 1) A SHIFT REACTOR TO PRODUCE ADDITIONAL HYDROGEN 2) 2 PRESSURE SWING ADSORBERS (PSA¿S) TO PURIFY HYDROGEN 3) A 350 MMBTU/HR BOILER (EPN 7) TO GENERATE STEAM FIRING PSA TAIL GAS . THE BOILER EMITS MORE THAN 100 TPY CO, MAKING THIS PERMIT A PSD PROJECT FOR CO, PSD PERMIT NO. P1044. THE COMPANY ALSO INCLUDED THE FOLLOWING PERMIT BY RULES: AUTHORIZATION TYPE NUMBER DESCRIPTION PBR 43611 A DIESEL FUEL TANK (EPN 8), MEETS BACT, SEE SOURCES AND CONTROLS PBR 43611 A PROCESS STEAM VENT (EPN SVENT1), MEETS BACT, SEE SOURCES AND CONTROLS 106.511 NONE AN EMERGENCY GENERATOR (EPN 9), MEETS BACT, SEE SOURCES AND CONTROLS FINALLY, THE COMPANY AUTHORIZED A START UP PROCESS VENT FOR THE SHIFT REACTOR STEAM DRUM. THERE ARE VIRTUALLY NO VOC EMISSIONS FROM THE VENT. THERE WAS A SMALL INCREASE IN FUGITIVE EMISSIONS DUE TO NEW PIPING FOR THE SHIFT REACTOR SYSTEM.

	Process Information						
					Throughput		Process Notes
RBLC ID:	Process ID	Process Name	Process Type	Primary Fuel	Value	Unit	
OK-0135	OK-0135-Process 1	CARBON DIOXIDE VENT	61.999		36.5	T/H	36.5 TONS/H CO2 VENTED LIMIT
LA-0148	LA-0148-Process 1	MULTIPLE HEARTH FURNACES / AFTERBURNERS	11.110	COAL	7.78	LB/YR E +08	4 MULTI-HEARTH FURNACES. PROCESSES LIGNITE COAL ALSO COMBUSTS 13.2 MM BTU /HR NATURAL GAS TO BALANCE HEAT LOADS.
AL-0231	AL-0231-Process 1	VACUUM DEGASSER BOILER	13.310	NATURAL GAS	95	MMBTU/H	
TX-0481	TX-0481-Process 1	EMERGENCY GENERATOR	19.800				CO EMISSIONS ARE ELIGIBLE FOR PSD

	Emissions Information																		
					Emission Limit 1			Emission Limit 2:			Standard Emission Limit:								
RBLC ID:	Process ID	Pollutant Name	Control Method Code	Control Method Description:	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Case-by-Case Basis:	Other Applicable Requirements	Did factors, other then air pollution technology considerations influence the BACT decisions?	Compliance Verified	Cost Verified (Y/N)?	Pollutants/ Compliance Notes
OK-0135	OK-0135-Process 1	Carbon Dioxide	N	GOOD OPERATION PRACTICES.	3.65	LB/H	1-HOUR/8-HOUR	0			0			BACT-PSD	N/A	U	Unknown	No	
LA-0148	LA-0148-Process 1	Carbon Dioxide	A	AFTERBURNER AND GOOD COMBUSTION PRACTICES	37.6	LB/H	3-HOUR	0			0			BACT-PSD	NSPS , SIP , OPERATING PERMIT , OTHER	U	Unknown	No	
AL-0231	AL-0231-Process 1	Carbon Dioxide	N		0.061	LB/MMBTU		5.8	LB/H		0			BACT-PSD		Y	Unknown	No	
TX-0481	TX-0481-Process 1	Carbon Dioxide	N		2.24	LB/H		0.99	T/YR		0			BACT-PSD		U	Unknown	No	

RBLC ID:	Permit Information												
	Corporate/ Company Name	Facility Name	State	EPA Region	Permit Number	SIC Code	NAICS Code	Application Accepted Received Date	Permit Issuance Date	Permit Type	Permit URL	Facility Description:	Permit Notes
*PA-0283	GRAYMONT PA INC	GRAYMONT PA INC/PLEASANT GAP & BELLEFONTE PLTS	PA	3	14-00002N		327410		11/19/2012 ACT	U: Unspecified		This plan approval is for the Kiln No. 8 project. WASTE OIL HEATER [BEL], PROPANE HEATER, PULVERIZED LIMESTONE SYSTEM, 136 HP DIESEL GENERATOR [PG], MISCELLANEOUS EMERGENCY GENERATORS, KILN NO. 8 PROJECT STONE RECLAMATION SYSTEM, PROCESSED STONE HANDLING, LIME KILN DUST HANDLING AND LOADING SYSTEM, LIME HANDLING AND STORAGE SYSTEM, LIME LOADING SYSTEM, EMERGENCY GENERATOR-ENGINES FOR COOLING FANS, PLS FABRIC COLLECTOR, ROTARY DRYER FABRIC COLLECTOR, STONE RECLAMATION FABRIC COLLECTOR, PROCESSED STONE AND LKD FABRIC COLLECTOR, LIME HANDLING AND STORAGE FABRIC COLLECTOR, LIME LOADING FABRIC COLLECTOR, KILN 6 BAGHOUSE, LIME KILN 7 SEMI-WET SCRUBBER, LIME KILN 7 FABRIC COLLECTOR, KILN NO. 8 BAGHOUSE NATURAL GAS SUPPLY BITUMINOUS COAL SUPPLY PETROLEUM COKE SUPPLY NO. 2 FUEL OIL STORAGE PROPANE STORAGE DIESEL FUEL STORAGE SPACE HEATER EXHAUSTS	Pursuant to the plantwide applicability limit (PAL) provisions of 40 CFR § 52.21(aa)(7), the total combined sulfur dioxide (SO2) emissions, including fugitive emissions, from the facility shall not exceed 302.6 tons in any 12 consecutive month period.
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/epsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	
GA-0143	JM HUBER CORP	HUBER ENGINEERED WOODS, LLC	GA	4	2493-157-0014-V-02-3	2493	321219		11/10/2011 ACT	A: New/Greenfield Facility			
GA-0143	JM HUBER CORP	HUBER ENGINEERED WOODS, LLC	GA	4	2493-157-0014-V-02-3	2493	321219		11/10/2011 ACT	A: New/Greenfield Facility			
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	IN	5	153-29394-00005	4911	221112	06/25/2010 ACT	11/10/2011 ACT	A: New/Greenfield Facility	HTTP://PERMITS.AIR.IDEM.IN.GOV/29394F.PDF	STATIONARY ELECTRIC POWER GENERATING PLANT	

	Process Information						
					Throughput		
RBLC ID:	**Process ID**	**Process Name**	**Process Type**	**Primary Fuel**	**Value**	**Unit**	**Process Notes**
*PA-0283	*PA-0283-Process 1	KILN NO. 8	90.019	Pipeline quality natural gas	0		Source ID P418 consists of a 660 tons per day, twin-shaft vertical lime kiln, designated as Kiln No. 8, that is equipped with 66 natural gas fuel delivery lances (2 sets of 33) with a total approximate heat input (HHV) equal to 100.4 MMBtu/hr. The air contaminant emissions from the kiln shall be controlled by the installation of ID C418 which is a pulse jet fabric collector, designated as 328-PDC-870. The fabric collector shall have a minimum fabric area of 25,536 square feet and handle no more than 75,000 actual cubic feet per minute. The permittee shall install, maintain, certify and operate a continuous emission monitoring system (CEMS) for nitrogen oxides (expressed as NO2), carbon monoxide, and sulfur oxides (expressed as SO2) emissions and opacity monitoring.
*IA-0105	*IA-0105-Process 1	Primary Reformer	61.012	natural gas	1.13	million cubic feet/hr	
*IA-0105	*IA-0105-Process 1	Nitric Acid Plant	62.014		1905	metric tons/day	
*IA-0105	*IA-0105-Process 1	Auxiliary Boiler	11.31	natural gas	472.4	MMBTU/hr	There are four (4) natural gas pilots
*IA-0105	*IA-0105-Process 1	Ammonia Flare	19.31	natural gas	0.4	MMBTU/H	rated @ 2,000 KW
*IA-0105	*IA-0105-Process 1	Emergency Generator	17.11	diesel fuel	142	GAL/H	rated @ 235 KW
*IA-0105	*IA-0105-Process 1	Fire Pump	17.21	diesel fuel	14	GAL/H	
*IA-0105	*IA-0105-Process 1	Startup Heater	12.31	Natural gas	110.12	MMBTU/H	
GA-0143	GA-0143-Process 1	WELLONS FURNACE	12.120	WOOD WASTE	150	MMBTU/H	BACT FOR THE FURNANCE/DRYER EXHAUST AS A SINGLE EMISSION SOURCE, SINCE THESE PROCESSES SHARE AIRFLOWS AND EXHAUST THROUGH A COMMON MANIFOLD
GA-0143		DRYER SYSTEM	12.120	WOOD WASTE	50	ODT/H	BACT FOR THE FURNANCE/DRYER EXHAUST IS EVALUATED AS A SIGNEL EMISSION SOURCE, SINCE THESE PROCESSES SHARE AIRFLOWS AND EXHAUST THROUGH A COMMON MANIFOLD
IN-0135		4-STROKE LEAN BURN COAL BED METHANE (CBM)-FIRED RECIPROCATING INTERNAL COMUBSTION ENGINES (RICE)	17.150	COAL BED METHANE	4601	BRAKE HORSEPOWER	THERE ARE 8 OF THESES PROCESSES

	Emissions Information																		
					Emission Limit 1			Emission Limit 2:			Standard Emission Limit:								
RBLC ID:	Process ID	Pollutant Name	Control Method Code	Control Method Description:	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Case-by-Case Basis:	Other Applicable Requirements	Did factors, other then air pollution technology considerations influence the BACT decisions?	Compliance Verified	Cost Verified (Y/N)?	Pollutants/ Compliance Notes
*PA-0283	*PA-0283-Process 1	Methane	N		3.65	MMBTU (HHV)	PER TON OF LIME	0			0			BACT-PSD	NSPS	U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Methane	P	good combustion practices	0.0023	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Methane	P	good operational practices	40	PPMV	AVERAGE OF 3 STACK TEST RUNS	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Methane	P	good combustion practices	0.0023	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Methane	P	work practice/good combustion practices	0			0			0			BACT-PSD		U	Unknown	No	There is no numeric emission limit in the permit.
*IA-0105	*IA-0105-Process 1	Methane	P	good combustion practices	0.0001	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Methane	P	good combustion practices	0.0001	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Methane	P	good combustion practices	0.0023	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	0			0			BACT-PSD		U	Unknown	No	
GA-0143	GA-0143-Process 1	Methane	P	THE COMBUSTION OF BIOMASS AND THE USE OF GOOD COMBUSTION/OPERATING PRACTICES TO CONTROL GHGS.	0		YEAR ROUND	0			0			BACT-PSD	SIP , OPERATING PERMIT	U	Unknown	No	EMISSION LIMIT 1: FIRE BIOGENIC CARBON STOCK POLLUTANT NAME: CO2E (CO2, CH4)
GA-0143	GA-0143-Process 1	Methane	P	THE COMBUSTION OF BIOMASS AND THE USE OF GOOD COMBUSTION/OPERATING PRACTICES TO CONTROL GHGS.	0		YEAR ROUND	0			0			BACT-PSD	SIP , OPERATING PERMIT	Y	Unknown	No	EMISSION LIMIT 1: FIRE BIOGENIC CARBON STOCK POLLUTANT NAME: CO2E (CO2, CH4)
IN-0135		Methane	P	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	9.57	LB/MW-H	3 HOURS	139.4	T/12 CONSEC MONTHS	12 CONSECUTIVE MONTH PERIOD	0			OTHER CASE-BY-CASE	N/A	U	Unknown	No	PERFORM REGULAR MAINTENANCE USING THE MANUFACTURER'S OR OPERATOR'S MAINTENANCE PROCEDURES; KEEP RECORDS OF ANY MAINTENANCE THAT WOULD

RBLC ID:	Permit Information												
	Corporate/ Company Name	Facility Name	State	EPA Region	Permit Number	SIC Code	NAICS Code	Application Accepted Received Date	Permit Issuance Date	Permit Type	Permit URL	Facility Description:	Permit Notes
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	IN	5	153-29394-00005	4911	221112	06/25/2010 ACT	11/10/2011 ACT	A: New/Greenfield Facility	HTTP://PERMITS.AIR.IDEM.IN.GOV/29394F.PDF	STATIONARY ELECTRIC POWER GENERATING PLANT	
LA-0254	ENTERGY LOUISIANA LLC	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	6	PSD-LA-752	4911	221112	09/14/2010 ACT	08/16/2011 ACT	B: Add new process to existing facility		1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS BACT FOR GREENHOUSE GASES (CO2E) FROM THE COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B) IS OPERATING PROPERLY AND PERFORMING NECESSARY ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT TO MAINTAIN THE GROSS HEAT RATE AT OR BELOW 7630 BTU/KW-HR (HHV) (ANNUAL AVERAGE).
LA-0254	ENTERGY LOUISIANA LLC	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	6	PSD-LA-752	4911	221112	09/14/2010 ACT	08/16/2011 ACT	B: Add new process to existing facility		1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS BACT FOR GREENHOUSE GASES (CO2E) FROM THE COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B) IS OPERATING PROPERLY AND PERFORMING NECESSARY ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT TO MAINTAIN THE GROSS HEAT RATE AT OR BELOW 7630 BTU/KW-HR (HHV) (ANNUAL AVERAGE).
LA-0254	ENTERGY LOUISIANA LLC	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	6	PSD-LA-752	4911	221112	09/14/2010 ACT	08/16/2011 ACT	B: Add new process to existing facility		1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS BACT FOR GREENHOUSE GASES (CO2E) FROM THE COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B) IS OPERATING PROPERLY AND PERFORMING NECESSARY ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT TO MAINTAIN THE GROSS HEAT RATE AT OR BELOW 7630 BTU/KW-HR (HHV) (ANNUAL AVERAGE).
OH-0330	RUMPKE SANITARY LANDFILL	RUMPKE SANITARY LANDFILL	OH	5	07-00574	4953	562212	06/19/2008 ACT	12/23/2008 ACT	C: Modify process at existing facility		MUNICIPAL SOLID WASTE LANDFILL, MODIFICATION TO INCREASE THE CAPACITY AND TO ALLOW FOR THE DISPOSAL OF ASBESTOS CONTAINING WASTES.	Expansion of RUMPKE landfill and added requirement to implement an asbestos spill contingency plan. This existing landfill not previously entered into RBLC.
OH-0330	RUMPKE SANITARY LANDFILL	RUMPKE SANITARY LANDFILL	OH	5	07-00574	4953	562212	06/19/2008 ACT	12/23/2008 ACT	C: Modify process at existing facility		MUNICIPAL SOLID WASTE LANDFILL, MODIFICATION TO INCREASE THE CAPACITY AND TO ALLOW FOR THE DISPOSAL OF ASBESTOS CONTAINING WASTES.	Expansion of RUMPKE landfill and added requirement to implement an asbestos spill contingency plan. This existing landfill not previously entered into RBLC.

RBLC ID:	Process Information						
	Process ID	Process Name	Process Type	Primary Fuel	Throughput		Process Notes
					Value	Unit	
IN-0135		COAL BED METHANE-FIRED STANDBY FLARE W/PROPANE-FIRED PILOT	19.390	COAL BED METHANE	25	MMBTU/H	WITH 0.8 MMBTU/HR FOR THE PILOT WITH PROPANE AS THE PILOT'S PRIMARY FUEL
LA-0254		AUXILIARY BOILER (AUX-1)	11.310	NATURAL GAS	338	MMBTU/H	
LA-0254		EMERGENCY DIESEL GENERATOR	17.110	DIESEL	1250	HP	
LA-0254		EMERGENCY FIRE PUMP	17.210	DIESEL	350	HP	
OH-0330		MUNICIPAL WASTE LANDFILL	29.900				THE EXISTING LANDFILL IS NOT SUBJECT TO THE REQUIREMENTS OF NSPS SUBPART WWW BECAUSE THE 5-YEAR NMOC EMISSION REPORT SUBMITTED ON 6/12/03 SHOWED NMOC EMISSIONS WELL BELOW 50 MG/YR. WHEN NMOC EMISSIONS ARE CALCULATED TO EQUAL OR EXCEED THE 50 MG LIMIT THE FACILITY WILL INSTALL LANDFILL WELLS THAT MEET THE REQUIREMENTS OF THE SUBPART.
OH-0330		ENCLOSED COMBUSTORS (4)	29.900	LANDFILL GAS			

RACT/BACT/LAER CLEARINGHOUSE DATABASE SEARCH RESULTS - CH_4 - ALL SOURCES
GHG PSD AIR PERMIT APPLICATION
FRAC III PROJECT
LONE STAR NGL MONT BELVIEU GAS PLANT

	Emissions Information																		
					Emission Limit 1			Emission Limit 2:			Standard Emission Limit:								
RBLC ID:	Process ID	Pollutant Name	Control Method Code	Control Method Description:	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Case-by-Case Basis:	Other Applicable Requirements	Did factors, other then air pollution technology considerations influence the BACT decisions?	Compliance Verified	Cost Verified (Y/N)?	Pollutants/ Compliance Notes
IN-0135		Methane	P	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	0.06	LB/MW-H		0.08	T/12 CONSEC MONTHS	12 MONTH CONSECUTIVE PERIOD	0			OTHER CASE-BY-CASE	N/A	U	Unknown	No	PERFORM REGULAR MAINTENANCE USING THE MANUFACTURER'S OR OPERATOR'S MAINTENANCE PROCEDURES; KEEP RECORDS OF
LA-0254		Methane	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0022	LB/MMBTU		0			0.0022	LB/MMBTU		BACT-PSD	OPERATING PERMIT	U	Unknown	No	
LA-0254		Methane	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0061	LB/MMBTU		0			0.0061	LB/MMBTU		BACT-PSD	OPERATING PERMIT	U	Unknown	No	
LA-0254		Methane	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0061	LB/MMBTU		0			0.0061	LB/MMBTU		BACT-PSD	OPERATING PERMIT	U	Unknown	No	
OH-0330		Methane	A	4 ENCLOSED COMBUSTORS AND 5 CANDLESTICK FLARES; AND MAIN OPEN FLARE FOR EXISTING LANDFILL	75712	T/YR	FROM EXISTING LF AND FUTURE EXPANSION	500	PPM	QUARTERLY SURFACE MONITORING	0			N/A	NSPS , SIP	U	Unknown	No	THIS IS THE PERMITTED LIMIT THAT INCLUDES THE FUTURE EXPANSION.
OH-0330		Methane	N	COMBUSTORS ARE THE CONTROL	299.01	LB/H		1309.66	T/YR	FROM EXISTING LF AND FUTURE EXPANSION	0			N/A	NSPS	U	Unknown	No	CALCULATED FROM EMISSION FACTORS FROM USEPA'S LANDFILL GAS EMISSIONS MODEL AND AP-42 SECTION 2.4

	Permit Information												
RBLC ID:	**Corporate/ Company Name**	**Facility Name**	**State**	**EPA Region**	**Permit Number**	**SIC Code**	**NAICS Code**	**Application Accepted Received Date**	**Permit Issuance Date**	**Permit Type**	**Permit URL**	**Facility Description:**	**Permit Notes**
OH-0330	RUMPKE SANITARY LANDFILL	RUMPKE SANITARY LANDFILL	OH	5	07-00574	4953	562212	06/19/2008 ACT	12/23/2008 ACT	C: Modify process at existing facility		MUNICIPAL SOLID WASTE LANDFILL, MODIFICATION TO INCREASE THE CAPACITY AND TO ALLOW FOR THE DISPOSAL OF ASBESTOS CONTAINING WASTES.	Expansion of RUMPKE landfill and added requirement to implement an asbestos spill contingency plan. This existing landfill not previously entered into RBLC.
OH-0330	RUMPKE SANITARY LANDFILL	RUMPKE SANITARY LANDFILL	OH	5	07-00574	4953	562212	06/19/2008 ACT	12/23/2008 ACT	C: Modify process at existing facility		MUNICIPAL SOLID WASTE LANDFILL, MODIFICATION TO INCREASE THE CAPACITY AND TO ALLOW FOR THE DISPOSAL OF ASBESTOS CONTAINING WASTES.	Expansion of RUMPKE landfill and added requirement to implement an asbestos spill contingency plan. This existing landfill not previously entered into RBLC.
MD-0040	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	CPV ST CHARLES	MD	3	CPCN CASE NO. 9129	1731	221122		11/12/2008 ACT	A: New/Greenfield Facility		640 MW GENERATING FACILITY	
OH-0281	RUMPKE SANITARY LANDFILL, INC	RUMPKE SANITARY LANDFILL, INC	OH	5	14-05824, 14-05292	4953	562212	03/19/2002 ACT	06/10/2004 ACT	A: New/Greenfield Facility		HAMILTON COUNTY LANDFILL WITH LANDFILL GAS PRODUCTION	LANDFILL WITH TOTAL CAPACITY OF 75,032,000 TONS OF COMPACTE WASTE. ANNUAL LANDFILL GAS PRODUCTION OF 11,621 MMCF/YR AT 1.33 MMCF/H. LANDFILL SOUTHERN EXPANSION, MODIFICATION WITH NEW LANDFILL GAS RECOVERY PLANT
OH-0281	RUMPKE SANITARY LANDFILL, INC	RUMPKE SANITARY LANDFILL, INC	OH	5	14-05824, 14-05292	4953	562212	03/19/2002 ACT	06/10/2004 ACT	A: New/Greenfield Facility		HAMILTON COUNTY LANDFILL WITH LANDFILL GAS PRODUCTION	LANDFILL WITH TOTAL CAPACITY OF 75,032,000 TONS OF COMPACTE WASTE. ANNUAL LANDFILL GAS PRODUCTION OF 11,621 MMCF/YR AT 1.33 MMCF/H. LANDFILL SOUTHERN EXPANSION, MODIFICATION WITH NEW LANDFILL GAS RECOVERY PLANT

	Process Information						
					Throughput		
RBLC ID:	Process ID	Process Name	Process Type	Primary Fuel	Value	Unit	Process Notes
OH-0330		CANDLESTICK FLARE (5)	29.900	LANDFILL GAS			
OH-0330		OPEN FLARE	29.900	LANDFILL GAS			MAIN FLARE FOR CONTROL OF LANDFILL GAS AND ODORS FROM EXISTING LANDFILL, NOT SUBJECT TO THE CONTROL REQUIREMENTS OF THE NSPS, SUBPART WWW, BECAUSE NON-METHANE ORANIC COMPOUND EMISSIONS ARE CALCULATED TO BE LESS THAN 50 MEGAGRAMS/YR.
MD-0040		INTERNAL COMBUSTION ENGINE - EMERGENCY FIRE WATER PUMP	17.210	DIESEL	300	HP	
OH-0281		NEW SOLID WASTE DISPOSAL WITH LANDFILL GAS GENERATION	29.900		42760000	TONS OF WASTE-EXPANS	LANDFILL EXPANSION OF 42,760,000 TONS OF COMPACTED WASTE CAPACITY LANDFILL ADDITION WITH AN ADDITIONAL 8,831 MMCF OF LANDFILL GAS PRODUCTION/YR.
~~OH-0281~~		EXISTING SOLID WASTE DISPOSAL WITH LANDFILL GAS GENERATION	29.900		32272000	TONS OF WASTE	EXISTING FACILITY PRIOR TO APPLICATION FOR EXPANSION.

	Emissions Information																		
					Emission Limit 1			Emission Limit 2:			Standard Emission Limit:								
RBLC ID:	Process ID	Pollutant Name	Control Method Code	Control Method Description:	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Case-by-Case Basis:	Other Applicable Requirements	Did factors, other then air pollution technology considerations influence the BACT decisions?	Compliance Verified	Cost Verified (Y/N)?	Pollutants/ Compliance Notes
OH-0330		Methane	N	FLARE IS CONTROL	25	LB/H		109.45	T/YR		0			N/A	NSPS , SIP	U	Unknown	No	
OH-0330		Methane	N	FLARE IS CONTROL	25	LB/H		109.45	T/YR		0			N/A	NSPS , SIP	U	Unknown	No	
MD-0040		Methane	N		3	G/HP-H		0			0			BACT-PSD	NSPS	U	Unknown	No	COMBINED LIMIT OF NOX AND NON-METHANE HYDROCARBON
OH-0281		Methane	A	ACTIVE GAS COLLECTION AND CONTROL SYSTEM: FLARE; LANDFILL GAS RECOVERY FOR SALE/USE; OR CONTROL BY A THERMAL OXIDIZER	1563	T/YR		0			0			BACT-PSD	NSPS , SIP	U	Unknown	No	
~~OH-0281~~		Methane	A	ACTIVE GAS COLLECTION AND CONTROL SYSTEM: FLARE; LANDFILL GAS RECOVERY FOR SALE/USE; OR CONTROL BY A THERMAL OXIDIZER	599	T/YR		0			0			BACT-PSD	NSPS , SIP	U	Unknown	No	

	Permit Information												
RBLC ID:	Corporate/ Company Name	Facility Name	State	EPA Region	Permit Number	SIC Code	NAICS Code	Application Accepted Received Date	Permit Issuance Date	Permit Type	Permit URL	Facility Description:	Permit Notes
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/eepsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/eepsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/eepsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/eepsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	
*IA-0105		IOWA FERTILIZER COMPANY	IA	7	12-219	2873	325311	08/03/2012 ACT	10/26/2012 ACT	A: New/Greenfield Facility	https://aqbweb.iowadnr.gov/airpermit/eepsdpermit.jsp	NITROGENEOUS FERTILIZER MANUFACTURING	
GA-0143	JM HUBER CORP	HUBER ENGINEERED WOODS, LLC	GA	4	2493-157-0014-V-02-3	2493	321219		11/10/2011 ACT	A: New/Greenfield Facility			
GA-0143	JM HUBER CORP	HUBER ENGINEERED WOODS, LLC	GA	4	2493-157-0014-V-02-3	2493	321219		11/10/2011 ACT	A: New/Greenfield Facility			
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	IN	5	153-29394-00005	4911	221112	06/25/2010 ACT	11/10/2011 ACT	A: New/Greenfield Facility	HTTP://PERMITS.AIR.IDEM.IN.GOV/29394F.PDF	STATIONARY ELECTRIC POWER GENERATING PLANT	

RBLC ID:	Process Information						
	Process ID	Process Name	Process Type	Primary Fuel	Throughput Value	Throughput Unit	Process Notes
*IA-0105	*IA-0105-Process 1	Primary Reformer	61.012	natural gas	1.13	million cubic feet/hr	
*IA-0105	*IA-0105-Process 1	Nitric Acid Plant	62.014		1905	metric tons/day	
*IA-0105	*IA-0105-Process 1	Auxiliary Boiler	11.31	natural gas	472.4	MMBTU/hr	
*IA-0105	*IA-0105-Process 1	Ammonia Flare	19.31	natural gas	0.4	MMBTU/H	There are four (4) natural gas pilots
*IA-0105	*IA-0105-Process 1	Startup Heater	12.31	Natural gas	110.12	MMBTU/H	
GA-0143	GA-0143-Process 1	WELLONS FURNACE	12.120	WOOD WASTE	150	MMBTU/H	BACT FOR THE FURNANCE/DRYER EXHAUST AS A SINGLE EMISSION SOURCE, SINCE THESE PROCESSES SHARE AIRFLOWS AND EXHAUST THROUGH A COMMON MANIFOLD
GA-0143	GA-0143-Process 1	DRYER SYSTEM	12.120	WOOD WASTE	50	ODT/H	BACT FOR THE FURNANCE/DRYER EXHAUST IS EVALUATED AS A SIGNEL EMISSION SOURCE, SINCE THESE PROCESSES SHARE AIRFLOWS AND EXHAUST THROUGH A COMMON MANIFOLD
IN-0135		COAL BED METHANE CBM DEHYDRATOR UNITS (CBM-FIRED REBOILER AND FLASH TANK)	19.900	COAL BED METHANE	0.5	MMBTU/H	THERE ARE TWO OF THESE PROCESSES

	Emissions Information																		
					Emission Limit 1			Emission Limit 2:			Standard Emission Limit:								
RBLC ID:	Process ID	Pollutant Name	Control Method Code	Control Method Description:	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Case-by-Case Basis:	Other Applicable Requirements	Did factors, other then air pollution technology considerations influence the BACT decisions?	Compliance Verified	Cost Verified (Y/N)?	Pollutants/ Compliance Notes
*IA-0105	*IA-0105-Process 1	Nitrous Oxide (N2O)	P	good combustion practices	0.0006	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Nitrous Oxide (N2O)	A	De-N2O system	30	PPMV	AVERAGE OF 3 TEST RUNS	98	% REDUCTION	AVERAGE OF 3 TEST RUNS	0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Nitrous Oxide (N2O)	P	good combustion practices	0.0006	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	0			0			BACT-PSD		U	Unknown	No	
*IA-0105	*IA-0105-Process 1	Nitrous Oxide (N2O)	P	work practice/good combustion practices	0			0			0			BACT-PSD		U	Unknown	No	There is no numeric emission limit in the permit.
*IA-0105	*IA-0105-Process 1	Nitrous Oxide (N2O)	P	good combustion practices	0.0006	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	0			0			BACT-PSD		U	Unknown	No	
GA-0143	GA-0143-Process 1	Nitrous Oxide (N2O)	N	BASED ON ADVERSE CRITERIA POLLUTANT IMPACTS NO CONTROL HAS BEEN ESTABLISHED TO MINIMIZE N2O EMISSIONS.	0			0			0			BACT-PSD	NESHAP, SIP, OPERATING PERMIT	U	Unknown	No	POLLUTANT NAME: CO2E (N2O) GIVEN THE LOW N2O EMISSIONS RELATIVE TO NOX EMISSIONS FROM THE WOOD-FIRED FURNANCE (6 T/YR VERSUS 620 T/YR) AND THE RECENT PROPOSED STRENGTHENING OF THE 8-HR OZONE NAAQS INDICATING US EPA'S CONTINUED CONCERN OVER ADVERSE IMPACTS FROM OZONE FORMATION DUE TO NOX AND VOC EMISSIONS, IT IS NOT ACCEPTABLE TO CONTROL THE COMBUSTION PROCESSES OF THE FURNACE/DRYER TO REDUCE N2O EMISSIONS W/ A CONCURRENT INCREASE IN NOX.
GA-0143		Nitrous Oxide (N2O)	N	BASED ON ADVERSE CRITERIA POLLUTANT IMPACTS NO CONTROL HAS BEEN ESTABLISHED TO MINIMIZE N2O EMISSIONS	0			0			0			BACT-PSD	SIP, OPERATING PERMIT	Y	Unknown	No	POLLUTANT NAME: CO2E (N2O) GIVEN THE LOW N2O EMISSIONS RELATIVE TO NOX EMISSIONS FROM THE WOOD-FIRED FURNANCE (6 T/YR VERSUS 620 T/YR) AND THE RECENT PROPOSED STRENGTHENING OF THE 8-HR OZONE NAAQS INDICATING US EPA'S CONTINUED CONCERN OVER ADVERSE IMPACTS FROM OZONE FORMATION DUE TO NOX AND VOC EMISSIONS, IT IS NOT ACCEPTABLE TO CONTROL THE COMBUSTION PROCESSES OF THE FURNACE/DRYER TO REDUCE N2O EMISSIONS W/ A CONCURRENT INCREASE IN NOX.
IN-0135		Nitrous Oxide (N2O)	P	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	0.23	LB/MW-H		3.35	T/12 CONSEC MONTHS	12 CONSECUTIVE MONTH PERIOD	0			OTHER CASE-BY-CASE	N/A	U	Unknown	No	PERFORM REGULAR MAINTENANCE USING THE MANUFACTURER'S OR OPERATOR'S MAINTENANCE PROCEDURES; KEEP RECORDS OF ANY MAINTENANCE THAT WOULD HAVE A SIGNIFICANT EFFECT ON EMISSIONS; THE RECORDS MAY BE KEPT IN ELECTRONIC FORMAT; AND KEEP A COPY OF EITHER THE MANUFACTURER'S OR THE OPERATOR'S MAINTENANCE PROCEDURES. PSD BACT

RBLC ID:	Corporate/ Company Name	Facility Name	State	EPA Region	Permit Number	SIC Code	NAICS Code	Application Accepted Received Date	Permit Issuance Date	Permit Type	Permit URL	Facility Description:	Permit Notes
	Permit Information												
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	IN	5	153-29394-00005	4911	221112	06/25/2010 ACT	11/10/2011 ACT	A: New/Greenfield Facility	HTTP://PERMITS.AIR.IDEM.IN.GOV/29394F.PDF	STATIONARY ELECTRIC POWER GENERATING PLANT	
LA-0254	ENTERGY LOUISIANA LLC	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	6	PSD-LA-752	4911	221112	09/14/2010 ACT	08/16/2011 ACT	B: Add new process to existing facility		NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND	DATE = DATE OF ADMINISTRATIVE COMPLETENESS BACT FOR GREENHOUSE GASES (CO2E) FROM THE COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B) IS OPERATING PROPERLY AND PERFORMING NECESSARY ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT TO MAINTAIN THE GROSS HEAT RATE AT OR BELOW 7630 BTU/KW-HR (HHV) (ANNUAL
LA-0254	ENTERGY LOUISIANA LLC	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	6	PSD-LA-752	4911	221112	09/14/2010 ACT	08/16/2011 ACT	B: Add new process to existing facility		1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS BACT FOR GREENHOUSE GASES (CO2E) FROM THE COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B) IS OPERATING PROPERLY AND PERFORMING NECESSARY ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT TO MAINTAIN THE GROSS HEAT RATE AT OR BELOW 7630 BTU/KW-HR (HHV) (ANNUAL AVERAGE).
LA-0254	ENTERGY LOUISIANA LLC	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	6	PSD-LA-752	4911	221112	09/14/2010 ACT	08/16/2011 ACT	B: Add new process to existing facility		1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS BACT FOR GREENHOUSE GASES (CO2E) FROM THE COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B) IS OPERATING PROPERLY AND PERFORMING NECESSARY ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT TO MAINTAIN THE GROSS HEAT RATE AT OR BELOW 7630 BTU/KW-HR (HHV) (ANNUAL AVERAGE).

	Process Information						
					Throughput		
RBLC ID:	Process ID	Process Name	Process Type	Primary Fuel	Value	Unit	Process Notes
IN-0135		COAL BED METHANE-FIRED STANDBY FLARE W/PROPANE-FIRED PILOT	19.390	COAL BED METHANE	25	MMBTU/H	WITH 0.8 MMBTU/HR FOR THE PILOT WITH PROPANE AS THE PILOT'S PRIMARY FUEL
LA-0254		AUXILIARY BOILER (AUX-1)	11.310	NATURAL GAS	338	MMBTU/H	
LA-0254		EMERGENCY DIESEL GENERATOR	17.110	DIESEL	1250	HP	
LA-0254		EMERGENCY FIRE PUMP	17.210	DIESEL	350	HP	

	Emissions Information																		
					Emission Limit 1			Emission Limit 2:			Standard Emission Limit:								
RBLC ID:	Process ID	Pollutant Name	Control Method Code	Control Method Description:	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Value	Unit	Avg. Time/ Condition	Case-by-Case Basis:	Other Applicable Requirements	Did factors, other then air pollution technology considerations influence the BACT decisions?	Compliance Verified	Cost Verified (Y/N)?	Pollutants/ Compliance Notes
IN-0135		Nitrous Oxide (N2O)	P	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	0.05	LB/MW-H		0.08	T/YR	12 CONSECUTIVE MONTH PERIOD	0			OTHER CASE-BY-CASE	N/A	U	Unknown	No	PERFORM REGULAR MAINTENANCE USING THE MANUFACTURER'S OR OPERATOR'S MAINTENANCE PROCEDURES; KEEP RECORDS OF ANY MAINTENANCE THAT WOULD HAVE A SIGNIFICANT EFFECT ON EMISSIONS; THE RECORDS MAY BE KEPT IN ELECTRONIC FORMAT; AND KEEP A COPY OF EITHER THE MANUFACTURER'S OR THE OPERATOR'S MAINTENANCE PROCEDURES PSD BACT
LA-0254		Nitrous Oxide (N2O)	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0002	LB/MMBTU		0			0.0002	LB/MMBTU		BACT-PSD	OPERATING PERMIT	U	Unknown	No	
LA-0254		Nitrous Oxide (N2O)	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0014	LB/MMBTU		0			0.0014	LB/MMBTU		BACT-PSD	OPERATING PERMIT	U	Unknown	No	
LA-0254		Nitrous Oxide (N2O)	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0014	LB/MMBTU		0			0.0014	LB/MMBTU		BACT-PSD	OPERATING PERMIT	U	Unknown	No	

GOOD COMBUSTION PRACTICES

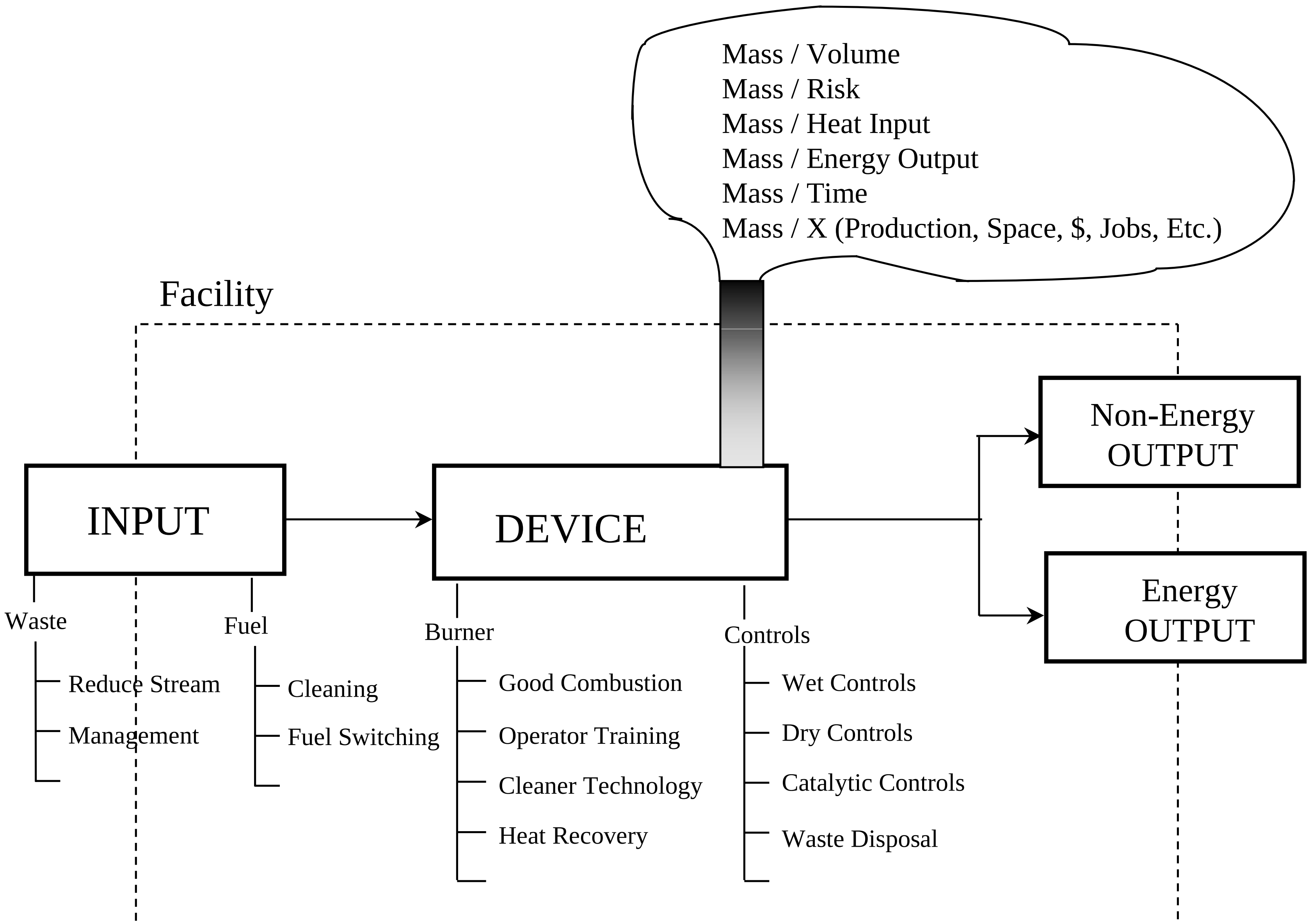
This guidance is intended to be used by the source work groups in their evaluation of alternative concepts regarding good combustion practices. While operator training could also be considered a good combustion practice, it is covered by separate guidance.

Examples of practices listed are intended to indicate the range of existing practices which are dependent on the specific type of equipment utilized and the fuel/waste input to the combustion device. All examples of specific techniques are not considered applicable to all combustion sources. The source work groups should be requested to evaluate techniques, practices, and possible standard approaches appropriate for subcategories or other subsets of sources.

Periodic checks and adjustments of combustion equipment are intended to occur at intervals appropriate for the source, with key combustion checks timed no less frequent than to coincide with overhaul frequencies.

Good Combustion Technique	Examples of Practices	Applicable Source Types	Possible 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	-Maintain written site specific operating procedures in accordance with GCPs, including startup, shutdown, malfunction
Maintenance knowledge	-Training on applicable equipment & procedures	All	-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	-Maintain site specific procedures for best/optimum maintenance practices -Scheduled periodic evaluation, inspection, overhaul as appropriate

Good Combustion Technique	Examples of Practices	Applicable Source Types	Possible Standard
Stoichiometric (fuel/air) ratio	-Burner & control adjustment based on visual checks -Burner & control adjustment based on continuous or periodic monitoring (O_2, CO, CO_2) -Fuel/air metering, ratio control -Oxygen trim control -CO control -Safety interlocks	Open combustion	-SR limits appropriate for unit design & fuel -Routine & periodic adjustment -CO limit
Firebox (furnace) residence time, temperature, turbulence	-Supplemental stream injection into active flame zone -Residence time by design (incinerators) -Minimum combustion chamber temperature (incinerators)	-Open combustion with supplemental vent streams -Incinerators	
Proper liquid atomization	-Differential pressure between atomizing media & liquid -Flow ratio of atomizing media to liquid flow -Liquid temp or viscosity -Flame appearance -Atomizer condition -Atomizing media quality	Open combustion with liquid fuel/waste	-Routine & periodic adjustments & checks -Maintain procedures to ensure adequate atomization & mixing with combustion air
Fuel/waste quality (analysis); fuel/waste handling	-Monitor fuel/waste quality -Fuel quality certification from supplier if needed -Periodic fuel/waste sampling and analysis -Fuel/waste handling practices	All- where appropriate	-Fuel/waste analysis where composition could vary & of significance to HAP emissions (e.g., not pipeline natural gas) -Fuel/waste handling procedures applicable to the fuel/waste
Fuel/waste sizing	-Fuel/waste sizing specification & checks -Pulverized coal fineness checks	Solid fuel/waste firing	-Specification appropriate for fuel/waste fired -Periodic checks
Combustion air distribution	-Adjustment of air distribution system based on visual observations -Adjustment of air distribution based on continuous or periodic monitoring	Mainly stoker and solid fuel firing	-Routine & periodic adjustments & checks
Fuel/waste dispersion	-Adjustment based on visual observations	Solid fuel/waste firing	-Routine & periodic adjustments & checks



Mass / Volume
Mass / Risk
Mass / Heat Input
Mass / Energy Output
Mass / Time
Mass / X (Production, Space, $, Jobs, Etc.)
Facility
INPUT
DEVICE
Non-Energy OUTPUT
Energy OUTPUT
Waste
Reduce Stream
Management
Fuel
Cleaning
Fuel Switching
Burner
Good Combustion
Operator Training
Cleaner Technology
Heat Recovery
Controls
Wet Controls
Dry Controls
Catalytic Controls
Waste Disposal

FIGURE 1

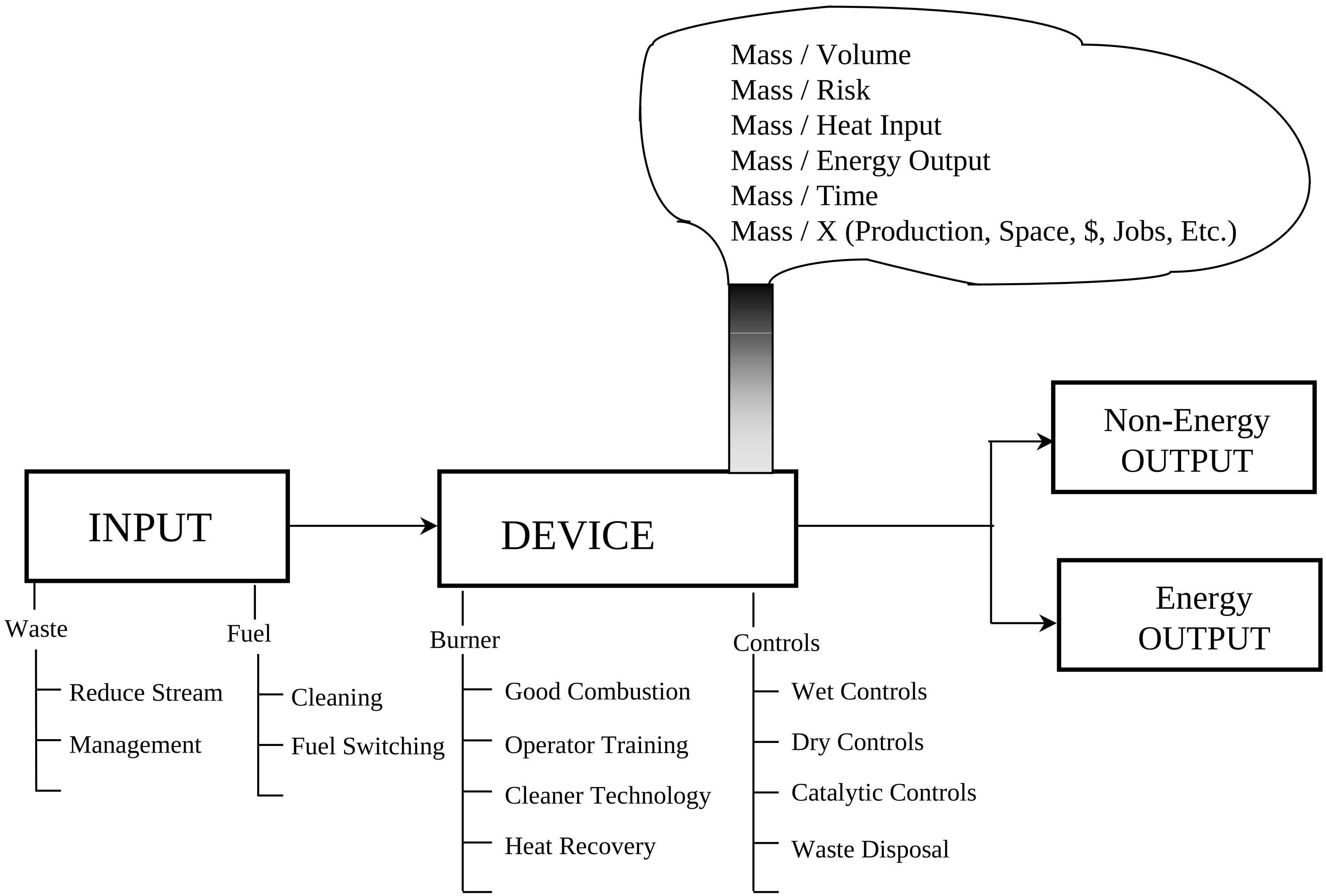
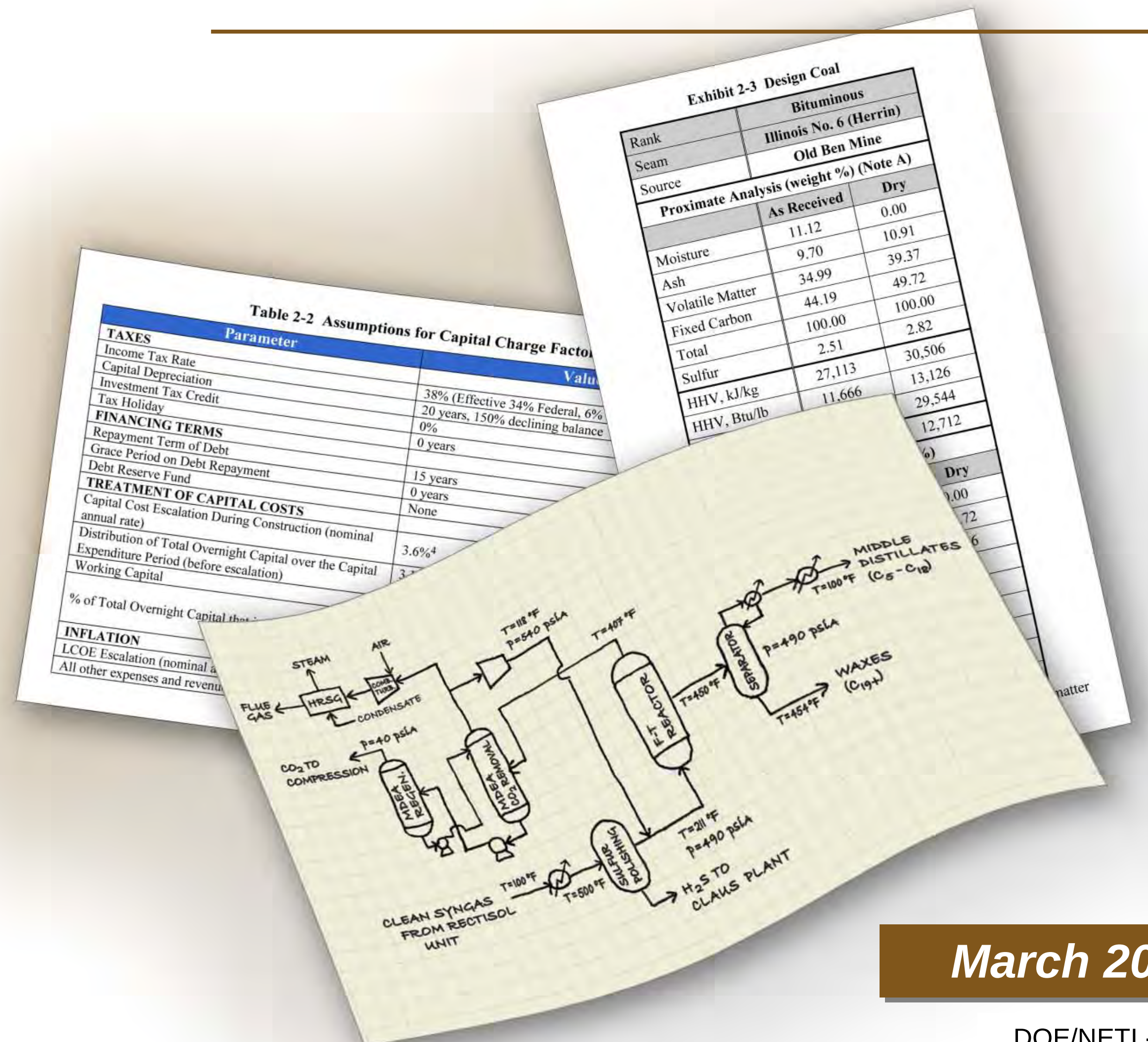

Mass / Volume
Mass / Risk
Mass / Heat Input
Mass / Energy Output
Mass / Time
Mass / X (Production, Space, $, Jobs, Etc.)
INPUT
DEVICE
Non-Energy OUTPUT
Energy OUTPUT
Waste
Reduce Stream
Management
Fuel
Cleaning
Fuel Switching
Burner
Good Combustion
Operator Training
Cleaner Technology
Heat Recovery
Controls
Wet Controls
Dry Controls
Catalytic Controls
Waste Disposal

FIGURE 2

the ENERGY lab

QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES

Estimating Carbon Dioxide Transport and Storage Costs



March 2010

DOE/NETL-2010/1447

NATIONAL ENERGY TECHNOLOGY LABORATORY

U.S. DEPARTMENT OF ENERGY

Quality Guidelines for Energy Systems Studies
Estimating CO_2 Transport, Storage & Monitoring Costs

Background

This paper explores the costs associated with geologic sequestration of carbon dioxide (CO_2). This cost is often cited at the flat figure of $5-10 per short ton of CO_2 removed, but estimates can vary with values as high as $23 per short ton having been published recently [1, 2, 3]. The variability of these costs is due in part to the wide range of transportation and storage options available for CO_2 sequestration, but may also relate to the dramatic rise of construction and material costs in the United States which has occurred over the last several years. This paper examines the transportation of CO_2 via pipeline to, and storage of that CO_2 in, a geologic formation representative of those identified in North America as having storage potential based on data available from the literature.

Approach

Geologic sequestration costs were assessed based on the pipeline transport and injection of super-critical CO_2 into a geologic reservoir representative of those identified in North America as having storage potential. High pressure (2,200 psig) CO_2 is provided by the power plant or energy conversion facility and the cost and energy requirements of compression are assumed by that entity. CO_2 is in a super-critical state at this pressure which is desirable for transportation and storage purposes.

CO_2 exits the pipeline terminus at a pressure of 1,200 psig, and the pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length. This exit pressure specification: (1) ensures that CO_2 remains in a supercritical state throughout the length of the pipeline regardless of potential pressure drops due to pipeline elevation change[1]; (2) is equivalent to the reservoir pressure – exceeding it after hydrostatic head is accounted for – alleviating the need for recompression at the storage site; and (3) minimizes the pipeline diameter required, and in turn, transport capital cost.

The required pipeline diameter was calculated iteratively by determining the diameter required to achieve a 1,000 psig pressure drop (2,200 psig inlet, 1,200 psig outlet) over the specified pipeline distance, and rounding up to the nearest even sized pipe diameter. The pipeline was sized based on the CO_2 output produced by the power plant when it is operating at full capacity (100% utilization factor) rather than the average capacity.

The storage site evaluated is a saline formation at a depth of 4,055 feet (1,236 meters) with a permeability of 22 md and down-hole pressure of 1,220 psig (8.4 MPa) [4].[2] This is considered an average storage site and requires roughly one injection well for each 10,300 short tons of CO_2 injected per day [4]. An overview of the geologic formation characteristics are shown in Table 1.

Table 1: Deep, Saline Formation Specification [4]

Parameter	Units	Average Case
Pressure	MPa (psi)	8.4 (1,220)
Thickness	m (ft)	161 (530)
Depth	m (ft)	1,236 (4,055)
Permeability	Md	22
Pipeline Distance	km (miles)	80 (50)
Injection Rate per Well	tonne (short ton) CO_2/day	9,360 (10,320)

[1] Changes in pipeline elevation can result in pipeline pressure reductions due to head losses, temperature variations or other factors. Therefore a 10% safety margin is maintained to ensure the CO_2 supercritical pressure of 1,070 psig is exceeded at all times.
[2] "md", or millidarcy, is a measure of permeability defined as 10^{-12} Darcy.

Cost Sources & Methodology

transport storage monitoring

The cost metrics utilized in this study provide a best estimate of T, S, & M costs for a "typical" sequestration project, and may vary significantly based on variables such as terrain to be crossed by the pipeline, reservoir characteristics, and number of land owners from which sub-surface rights must be acquired. Raw capital and operating costs are derived from detailed cost metrics found in the literature, escalated to June 2007-year dollars using appropriate price indices. These costs were then verified against values quoted by any industrial sources available. Where regulatory uncertainty exists or costs are undefined, such as liability costs and the acquisition of underground pore volume, analogous existing policies were used for representative cost scenarios.

The following sections describe the sources and methodology used for each metric.

Cost Levelization and Sensitivity Cases

Capital costs were levelized over a 30-year period and include both process and project contingency factors. Operating costs were similarly levelized over a 30-year period and a sensitivity analysis was performed to determine the effects of different pipeline lengths on overall and avoided costs as well as the distribution of transport versus storage costs.

In several areas, such as Pore Volume Acquisition, Monitoring, and Liability, cost outlays occur over a longer time period, up to 100 years. In these cases a capital fund is established based on the net present value of the cost outlay, and this fund is then levelized as described in the previous paragraph.

Following the determination of cost metrics, a range of CO_2 sequestration rates and transport distances were assessed to determine cost sensitivity to these parameters. Costs were also assessed in terms of both removed and avoided emissions cost, which requires power plant specific information such as plant efficiency, capacity factor, and emission rates. This paper presents avoided and removed emission costs for both Pulverized Coal (PC) and Integrated Gasification Combined Cycle (IGCC) cases using data from Cases 11 & 12 (Supercritical PC with and without CO_2 Capture) and Cases 1 & 2 (GEE Gasifier with and without CO_2 Capture) from the *Bituminous Baseline Study* [5].

Transport Costs

CO_2 transport costs are broken down into three categories: pipeline costs, related capital expenditures, and O&M costs.

Pipeline costs are derived from data published in the Oil and Gas Journal's (O&GJ) annual Pipeline Economics Report for existing natural gas, oil, and petroleum pipeline project costs from 1991 to 2003. These costs are expected to be analogous to the cost of building a CO_2 pipeline, as noted in various studies [4, 6, 7]. The University of California performed a regression analysis to generate the following cost curves from the O&GJ data: (1) Pipeline Materials, (2) Direct Labor, (3) Indirect Costs[3], and (4) Right-of-way acquisition, with each represented as a function of pipeline length and diameter [7].

Related capital expenditures were based on the findings of a previous study funded by DOE/NETL, *Carbon Dioxide Sequestration in Saline Formations – Engineering and Economic Assessment* [6]. This study utilized a similar basis for pipeline costs (Oil and Gas Journal Pipeline cost data up to the year 2000) but added a CO_2 surge tank and pipeline control system to the project.

Transport O&M costs were assessed using metrics published in a second DOE/NETL sponsored report entitled *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [4]. This study was chosen due to the reporting of O&M costs in terms of pipeline length, whereas the other studies mentioned above either (a)

[3] Indirect costs are inclusive of surveying, engineering, supervision, contingencies, allowances for funds used during construction, administration and overheads, and regulatory filing fees.

do not report operating costs, or (b) report them in absolute terms for one pipeline, as opposed to as a length- or diameter-based metric.

Storage Costs

Storage costs were broken down into five categories: (1) Site Screening and Evaluation, (2) Injection Wells, (3) Injection Equipment, (4) O&M Costs, and (5) Pore Volume Acquisition. With the exception of Pore Volume Acquisition, all of the costs were obtained from *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [4]. These costs include all of the costs associated with determining, developing, and maintaining a CO_2 storage location, including site evaluation, well drilling, and the capital equipment required for distributing and injecting CO_2.

Pore Volume Acquisition costs are the costs associated with acquiring rights to use the sub-surface area where the CO_2 will be stored, i.e. the pore space in the geologic formation. These costs were based on recent research by Carnegie Mellon University which examined existing sub-surface rights acquisition as it pertains to natural gas storage [8]. The regulatory uncertainty in this area combined with unknowns regarding the number and type (private or government) of property owners requires a number of “best engineering judgment” decisions to be made, as documented below under Cost Metrics.

Liability Protection

Liability Protection addresses the fact that if damages are caused by injection and long-term storage of CO_2, the injecting party may bear financial liability. Several types of liability protection schemas have been suggested for CO_2 storage, including Bonding, Insurance, and Federal Compensation Systems combined with either tort law (as with the Trans-Alaska Pipeline Fund), or with damage caps and preemption, as is used for nuclear energy under the Price Anderson Act [9].

At present, a specific liability regime has yet to be dictated either at a Federal or (to our knowledge) State level. However, certain state governments have enacted legislation which assigns liability to the injecting party, either in perpetuity (Wyoming) or until ten years after the cessation of injection operations, pending reservoir integrity certification, at which time liability is turned over to the state (North Dakota and Louisiana) [10, 11, 12]. In the case of Louisiana, a trust fund of five million dollars is established for each injector over the first ten years (120 months) of injection operations. This fund is then used by the state for CO_2 monitoring and, in the event of an at-fault incident, damage payments.

This study assumes that a bond must be purchased before injection operations are permitted in order to establish the ability and good will of an injector to address damages where they are deemed liable. A figure of five million dollars was used for the bond based on the Louisiana fund level. This Bond level may be conservative, in that the Louisiana fund covers both liability and monitoring, but that fund also pertains to a certified reservoir where injection operations have ceased, having a reduced risk compared to active operations. This cost may be updated as more specific liability regimes are instituted at the Federal or State levels. The Bond cost was not escalated.

Monitoring Costs

Monitoring costs were evaluated based on the methodology set forth in the IEA Greenhouse Gas R&D Programme’s *Overview of Monitoring Projects for Geologic Storage Projects* report [13]. In this scenario, operational monitoring of the CO_2 plume occurs over thirty years (during plant operation) and closure monitoring occurs for the following fifty years (for a total of eighty years). Monitoring is via electromagnetic (EM) survey, gravity survey, and periodic seismic survey, EM and gravity surveys are ongoing while seismic survey occurs in years 1, 2, 5, 10, 15, 20, 25, and 30 during the operational period, then in years 40, 50, 60, 70, and 80 after injection ceases.

Cost Metrics

The following sections detail the Transport, Storage, Monitoring, and Liability cost metrics used to determine CO_2 sequestration costs for the deep, saline formation described above. The cost escalation indices utilized to bring these metrics to June-2007 year dollars are also described below.

Transport Costs

The regression analysis performed by the University of California breaks down pipeline costs into four categories: (1) Materials, (2) Labor, (3) Miscellaneous, and (4) Right of Way. The Miscellaneous category is inclusive of costs such as surveying, engineering, supervision, contingencies, allowances, overhead, and filing fees [7]. These cost categories are reported individually as a function of pipeline diameter (in inches) and length (in miles) in Table 2 [7].

The escalated CO_2 surge tank and pipeline control system capital costs, as well as the Fixed O&M costs (as a function of pipeline length) are also listed in Table 2. Fixed O&M Costs are reported in terms of dollars per miles of pipeline per year.

Storage Costs

Storage costs were broken down into five categories: (1) Site Screening and Evaluation, (2) Injection Wells, (3) Injection Equipment, (4) O&M Costs, and (5) Pore Space Acquisition. Additionally, the cost of Liability Protection is also listed here for the sake of simplicity. Several storage costs are evaluated as flat fees, including Site Screening & Evaluation and the Liability Bond required for sequestration to take place.

As mentioned in the methodology section above, the site screening and evaluation figure of $4.7 million dollars is derived from *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [4]. Some sources in

Table 2: Pipeline Cost Breakdown [4, 6, 7]

Cost Type	Units	Cost
Pipeline Costs		
Materials	$ *Diameter (inches), Length (miles)*	$\$64,632 + \$1.85 \times L \times (330.5 \times D^2 + 686.7 \times D + 26,960)$
Labor	$ *Diameter (inches), Length (miles)*	$\$341,627 + \$1.85 \times L \times (343.2 \times D^2 + 2,074 \times D + 170,013)$
Miscellaneous	$ *Diameter (inches), Length (miles)*	$\$150,166 + \$1.58 \times L \times (8,417 \times D + 7,234)$
Right of Way	$ *Diameter (inches), Length (miles)*	$\$48,037 + \$1.20 \times L \times (577 \times D + 29,788)$
Other Capital		
CO_2 Surge Tank	$	$1,150,636
Pipeline Control System	$	$110,632
O&M		
Fixed O&M	$/mile/year	$8,632

industry, however, have quoted significantly higher costs for site screening and evaluation, on the magnitude of $100 to $120 million dollars. The higher cost may be reflective of a different criteria utilized in assessing costs, such as a different reservoir size – the reservoir assessed in the higher cost case could be large enough to serve 5 to 7 different injection projects – or uncertainty regarding the success rate in finding a suitable reservoir. Future analyses will examine the sensitivity of overall T, S, and M costs to higher site evaluation costs.

Pore Space Acquisition costs are based on acquiring long-term (100-year) lease rights and paying annual rent to land-owners once the CO_2 plume has reached their property. Rights are acquired by paying a one-time $500 fee to land-owners before injection begins, as per CMU's design criteria [8]. When the CO_2 plume enters into the area owned by that owner (as determined by annual monitoring), the injector begins paying an annual "rent" of $100 per acre to that owner for the period of up to 100 years from plant start-up [8]. A 3% annual escalation rate is assumed for rental rate over the 100-year rental period [8]. Similar to the CMU study, this study assumes that the plume area will cover rights need to be acquired from 120 landowners, however, a sensitivity analysis found that the overall acquisition costs were not significantly affected by this: increasing the

Table 3: Geologic Storage Costs [4, 8, 11]

Cost Type	Units	Cost
Capital		
Site Screening and Evaluation	$	$4,738,488
Injection Wells	$/injection well *(see formula)*[1,2,3]	$\$240{,}714 \times e^{0.0008 \times well-depth}$
Injection Equipment	$/injection well *(see formula)*[2]	$\$94{,}029 \times \left(\dfrac{7{,}389}{280 \times \#\,of\ injection\ wells}\right)^{0.5}$
Liability Bond	$	$5,000,000
Declining Capital Funds		
Pore Space Acquisition	$/short ton CO_2	$0.334/short ton CO_2
O&M		
Normal Daily Expenses (Fixed O&M)	$/injection well	$11,566
Consumables (Variable O&M)	$/yr/short ton CO_2/day	$2,995
Surface Maintenance (Fixed O&M)	*see formula*	$\$23{,}478 \times \left(\dfrac{7{,}389}{280 \times \#\,of\ injection\ wells}\right)^{0.5}$
Subsurface Maintenance (Fixed O&M)	$/ft-depth/inject. well	$7.08

[1]The units for the "well depth" term in the formula are meters of depth.
[2]The formulas at right describe the cost per injection well and in each case the number of injection wells should be multiplied the formula in order to determine the overall capital cost.
[3]The injection well cost is $508,652 per injection well for the 1,236 meter deep geologic reservoir assessed here.

number of owners to 120,000 resulted in a 110% increase in costs and a 1% increase in the overall LCOE of the plant [8]. However, this assumption will be revisited in future work.

To ensure that Pore Space Acquisition costs are met after injection ceases, a sinking capital fund is set up to pay for these costs by determining the present value of the costs over the 100-year period (30 years of injection followed by 70 additional years), assuming a 10% discount rate. The size of this fund – as described in Table 3 – is determined by estimating the final size of the underground CO_2 plume, based on both the total amount of CO_2 injected over the plant lifetime and the reservoir characteristics described in Table 1. After injection, the CO_2 plume is assumed to grow by 1% per year [9].

The remaining capital costs are based on the number of injection wells required, which has been calculated to be one injection well for every 10,320 short tons of CO_2 injected per day. O&M costs are based on the number of injection wells, the CO_2 injection rates, and injection well depth.

Monitoring Costs

Monitoring costs were evaluated based on the methodology set forth in the IEA Greenhouse Gas R&D Programme's *Overview of Monitoring Projects for Geologic Storage Projects* report [13]. In this scenario, operational monitoring of the CO_2 plume occurs over thirty years (during plant operation) and closure monitoring occurs for the following fifty years (for a total of eighty years). Monitoring is via electromagnetic (EM) survey, gravity survey, and periodic seismic survey, EM and gravity surveys are ongoing while seismic survey occurs in years 1, 2, 5, 10, 15, 20, 25, and 30 during the operational period, then in years 40, 50, 60, 70, and 80 after injection ceases.

Operational and closure monitoring costs are assumed to be proportional to the plume size plus a fixed cost, with closure monitoring costs evaluated at half the value of the operational costs. The CO_2 plume is assumed to grow from 18 square kilometers (km^2) after the first year to 310 km^2 in after the 30th (and final) year of injection. The plume grows by 1% per year thereafter, to a size of 510 km^2 after the 80th year [9].The present value of the life-cycle costs is assessed at a 10% discount rate and a capital fund is set up to pay for these costs over the eighty year monitoring cycle. The present value of the capital fund is equivalent to $0.377 per short ton of CO_2 to be injected over the operational lifetime of the plant.

Cost Escalation

Four different cost escalation indices were utilized to escalate costs from the year-dollars they were originally reported in, to June 2007-year dollars. These are the Chemical Engineering Plant Cost Index (CEPI), U.S. Bureau of Labor Statistics (BLS) Producer Price Indices (PPI), Handy-Whitman Index of Public Utility Costs (HWI), and the Gross-Domestic Product (GDP) Chain-type Price Index [14, 15, 16].

Table 4 details which price index was used to escalate each cost metric, as well as the year-dollars the cost was originally reported in. Note that this reporting year is likely to be different that the year the cost estimate is from.

Cost Comparisons

The capital cost metrics used in this study result in a pipeline cost ranging from $65,000 to $91,000/inch-Diameter/mile for pipeline lengths of 250 and 10 miles (respectively) and 3 to 4 million metric tonnes of CO_2 sequestered per year. When project and process contingencies of 30% and 20% (respectively) are taken into account, this range increases to $97,000 to $137,000/inch-Diameter/mile. These costs were compared to contemporary pipeline costs quoted by industry experts such as Kinder-Morgan and Denbury Resources for verification purposes. Table 5 details typical rule-of-thumb costs for various terrains and scenarios as quoted by a representative of Kinder-Morgan at the Spring Coal Fleet Meeting in 2009. As shown, the base NETL cost metric falls midway between the costs quoted for "Flat, Dry" terrain ($50,000/inch-Diameter/mile) and "High Population" or "Marsh, Wetland" terrain ($100,000/inch-Diameter/mile), although the metric is closer to the "High Population" or "Marsh, Wetland" when contingencies are taken into account [17]. These costs were stated to be inclusive of right-of-way (ROW) costs.

Table 4: Summary of Cost Escalation Methodology

Cost Metric	Year-$	Index Utilized
Transport Costs		
Pipeline Materials	2000	HWI: Steel Distribution Pipe
Direct Labor (Pipeline)	2000	HWI: Steel Distribution Pipe
Indirect Costs (Pipeline)	2000	BLS: Support Activities for Oil & Gas Operations
Right-of-Way (Pipeline)	2000	GDP: Chain-type Price Index
CO_2 Surge Tank	2000	CEPI: Heat Exchangers & Tanks
Pipeline Control System	2000	CEPI: Process Instruments
Pipeline O&M (Fixed)	1999	BLS: Support Activities for Oil & Gas Operations
Storage Costs		
Site Screening/Evaluation	1999	BLS: Drilling Oil & Gas Wells
Injection Wells	1999	BLS: Drilling Oil & Gas Wells
Injection Equipment	1999	HWI: Steel Distribution Pipe
Liability Bond	2008	n/a
Pore Space Acquisition	2008	GDP: Chain-type Price Index
Normal Daily Expenses (Fixed)	1999	BLS: Support Activities for Oil & Gas Operations
Consumables (Variable)	1999	BLS: Support Activities for Oil & Gas Operations
Surface Maintenance	1999	BLS: Support Activities for Oil & Gas Operations
Subsurface Maintenance	1999	BLS: Support Activities for Oil & Gas Operations
Monitoring		
Monitoring	2004	BLS: Support Activities for Oil & Gas Operations

Ronald T. Evans of Denbury Resources, Inc. provided a similar outlook, citing pipeline costs as ranging from $55,000/inch-Diameter/mile for a project completed in 2007, $80,000/inch-Diameter/mile for a recently completed pipeline in the Gulf Region (no wetlands or swamps), and $100,000/inch-Diameter/mile for a currently planned pipeline, with route obstacles and terrain issues cited as the reason for the inflated cost of that pipeline [18, 19]. Mr. Evans qualified these figures as escalated due to recent spikes in construction and material costs, quoting pipeline project costs of $30,000/inch-Diameter-mile as recent as 2006 [18, 19].

A second pipeline capital cost comparison was made with metrics published within the 2008 IEA report entitled *CO_2 Capture and Storage: A key carbon abatement option*. This report cites pipeline costs ranging from $22,000/inch-Diameter/mile to $49,000/inch-Diameter/mile (once escalated to December-2006 dollars), between 25% and 66% less than the lowest NETL metric of $65,000/inch-Diameter/mile [20].

The IEA report also presents two sets of flat figure geologic storage costs. The first figure is based on a 2005 Intergovernmental Panel on Climate Change report is similar to the flat figure quoted by other entities, citing

Table 5: Kinder-Morgan Pipeline Cost Metrics [17]

Terrain	Capital Cost ($/inch-Diameter/mile)
Flat, Dry	$50,000
Mountainous	$85,000
Marsh, Wetland	$100,000
River	$300,000
High Population	$100,000
Offshore (150'-200' depth)	$700,000

storage costs ranging from \$0.40 to \$4.00 per short ton of CO_2 removed [20]. This figure is based on sequestration in a saline formation in North America.

A second range of costs is also reported, citing CO_2 sequestration costs as ranging from \$14 to \$23 per short ton of CO_2 [13]. This range is based on a Monte Carlo analysis of 300 gigatonnes (Gt) of CO_2 storage in North America [20]. This analysis is inclusive of all storage options (geologic, enhanced oil recovery, enhanced coal bed methane, etc.), some of which are relatively high cost. This methodology may provide a more accurate cost estimate for large-scale, long-term deployment of CCS, but is a very high estimate for storage options that will be used in the next 50 to 100 years. For example, 300 Gt of storage represents capacity to store CO_2 from the next ~150 years of coal generation (2,200 million metric tonnes CO_2 per year from coal in 2007, assuming 90% capture from all facilities), meaning that certain high cost reservoirs will not come into play for another 100 or 150 years. This \$14 to \$23 per short ton estimate was therefore not viewed as a representative comparison to the NETL metric.

Results

Figure 1 describes the capital costs associated with the T&S of 10,000 short tons of CO_2 per day (2.65 million metric tonnes per year) for pipelines of varying length. This storage rate requires one injection well and is representative of the CO_2 produced by a 380 MW_g super-critical pulverized coal power plant, assuming 90% of the CO_2 produced by the plant is captured. Figure 2 presents similar information for Fixed, Variable, and total (assuming 100% capacity) operating expenses. In both cases, storage costs remain constant as the CO_2 flow rate and reservoir parameters do not change. Also, transport costs – which are dependent on both pipeline length and diameter – constitute the majority of the combined transport and storage costs for pipelines greater than 50 miles in length.

The disproportionately high cost of CO_2 transport (compared to storage costs) shown in Figures 1 and 2, and the direct dependence of pipeline diameter on the transport capital cost, prompted investigation into the effects of pipeline distance and CO_2 flow rate on pipeline diameter. Figure 3 describes the minimum required pipeline diameter as a function of pipeline length, assuming a CO_2 flow rate of 10,000 short tons per day (at 100%

Figure 1: Capital Cost vs. Pipeline Length

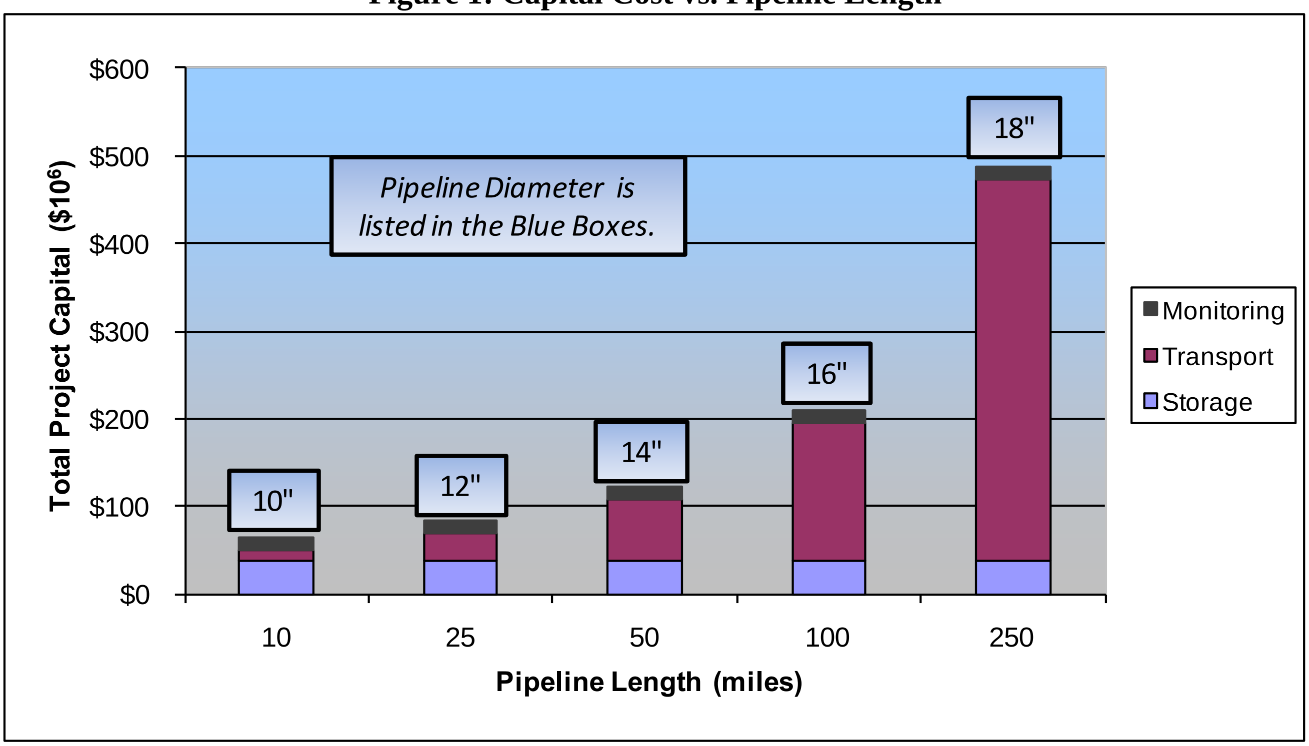
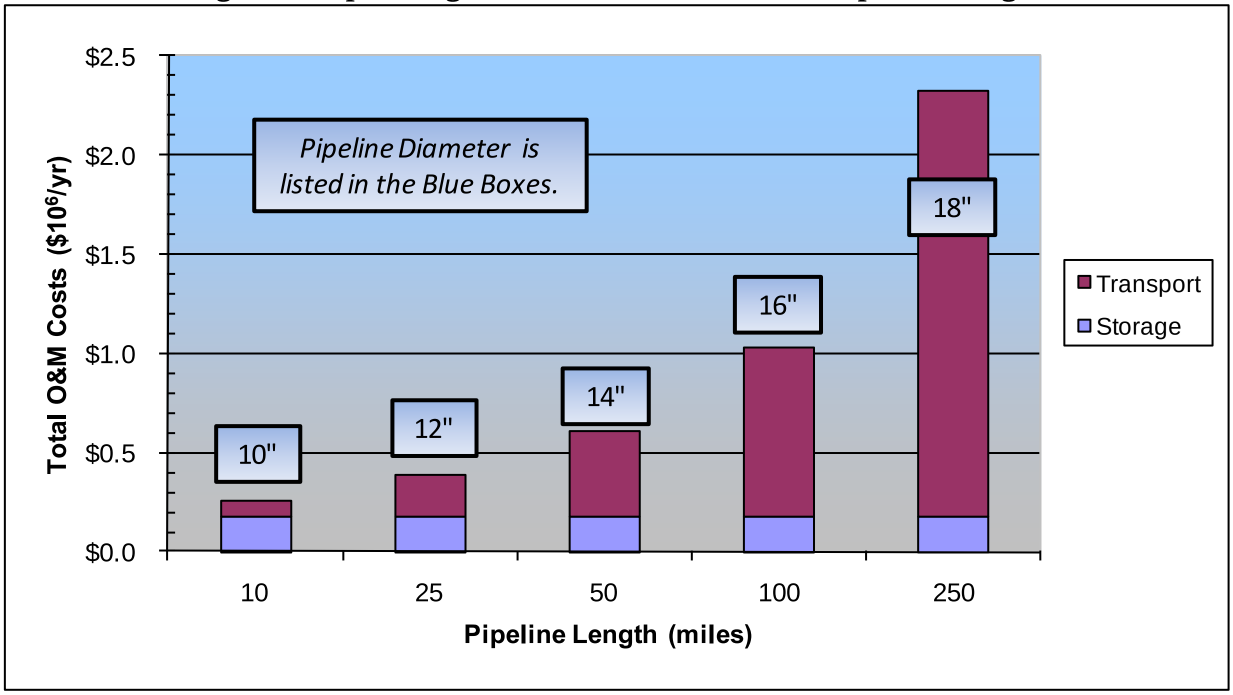


Figure 2: Operating and Maintenance Cost vs. Pipeline Length



utilization factor) and a pressure drop of 700 psi in order to maintain single phase flow in the pipeline (no recompression stages are utilized). Figure 4 is similar except that it describes the minimum pipe diameter as a function of CO_2 flow rate. A sensitivity analysis assessing the use of boost compressors and a smaller pipeline diameter has not yet been completed but may provide the ability to further reduce capital costs for sufficiently long pipelines.

Figure 3: Minimum Pipe Diameter as a function of Pipeline Length

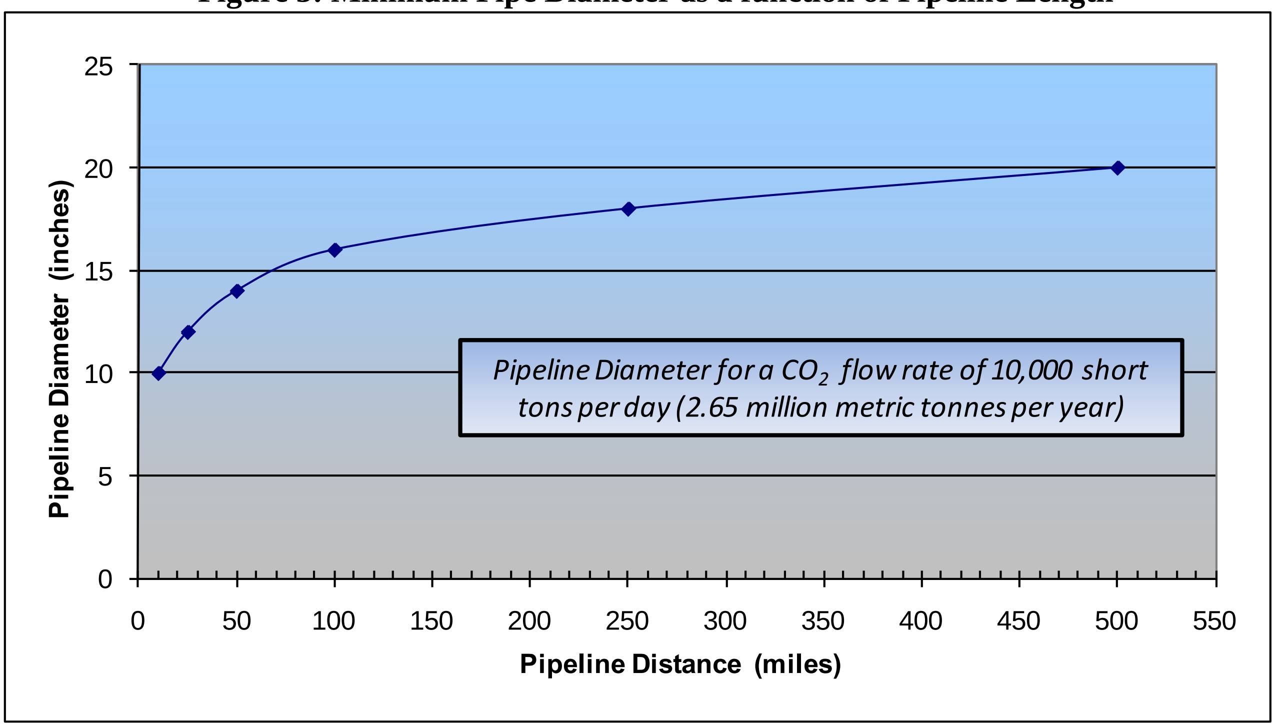
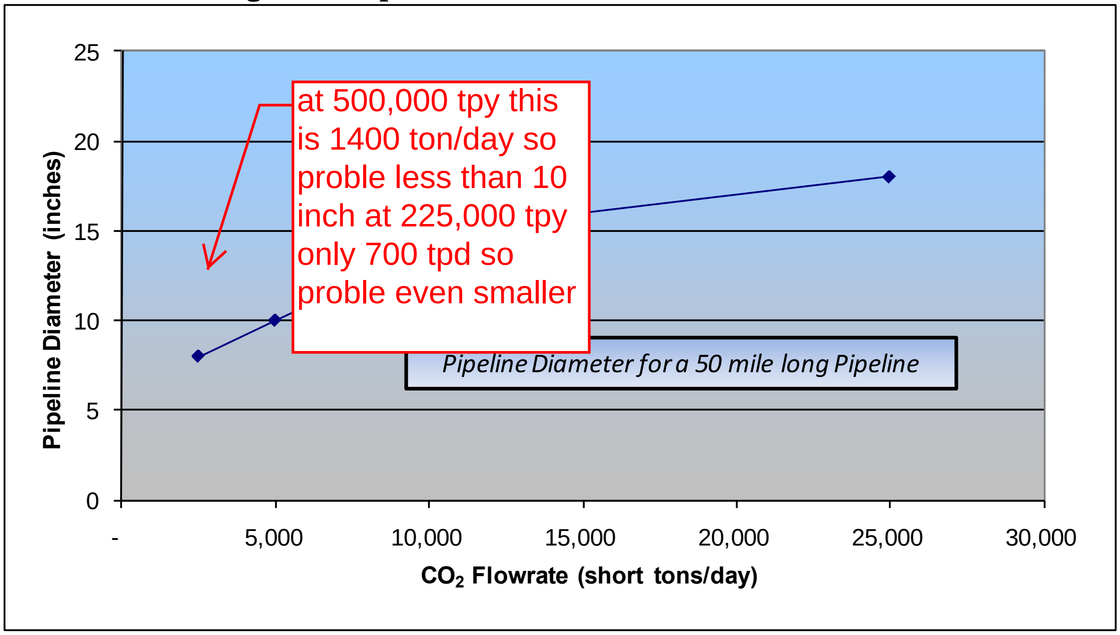


Figure 4: Pipe Diameter as a Function of CO_2 Flow Rate



Figures 5 and 6 describe the relationship of T&S costs to the flow rate of CO_2. The costs are evaluated for a 50 mile pipeline and a 700 psig CO_2 pressure drop over the length of the pipeline. Storage capital costs remain constant up until 10,000 short tons of CO_2 per day, above which a second injection well is needed and the cost increases as shown in Figure 5. A third injection well is needed for flow rates above 21,000 short tons per day and the capital requirement increases again for the 25,000 short tons per day flow rate due to an increase in pipeline diameter. Transport capital costs outweigh storage costs for all cases, as expected based on the results shown in Figure 1.

Unlike storage capital costs, the operating costs for storage constitute a significant portion of the total annual O&M costs – up to 44% at 25,000 short tons of CO_2 per day – as shown in Figure 6. Transport operating costs are constant with flow rate based on a constant pipeline length.

Figure 5: Capital Requirement vs. CO_2 Flow Rate

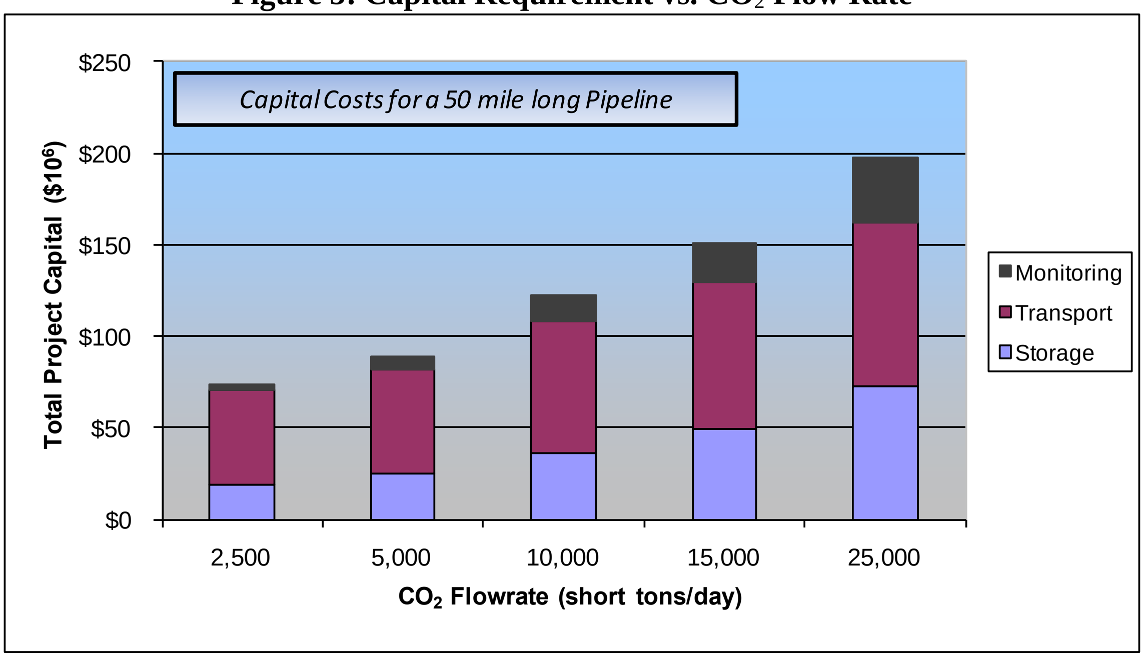
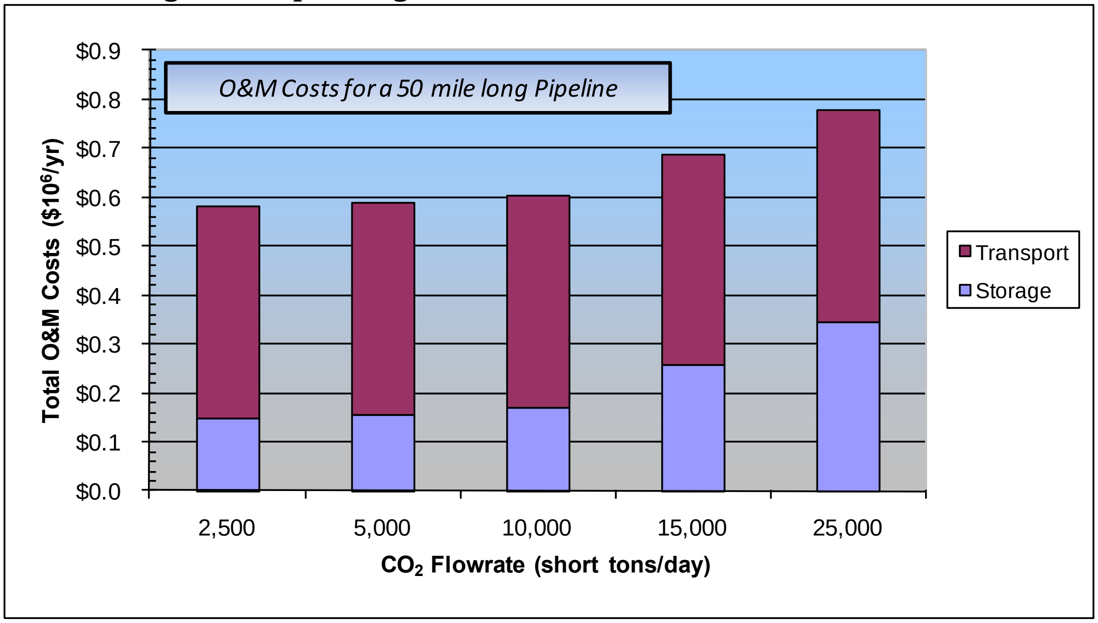


Figure 6: Operating and Maintenance Cost vs. CO_2 Flow Rate



Lastly, CO_2 avoidance and removal costs associated with T&S were determined for PC and IGCC reference plants found in the Baseline Study.[4] Because the CO_2 flow rate is defined by the reference plant, costs were determined as a function of pipeline length. Figure 7 shows that T&S avoided costs increase almost linearly with pipeline length and that there is very little difference between the PC and IGCC cases. This is the result of identical pipelines for each case (same distance, identical diameter) with only a change in capacity factor for each case. Figure 8 is similar to Figure 7 and shows the T&S removed emission cost.

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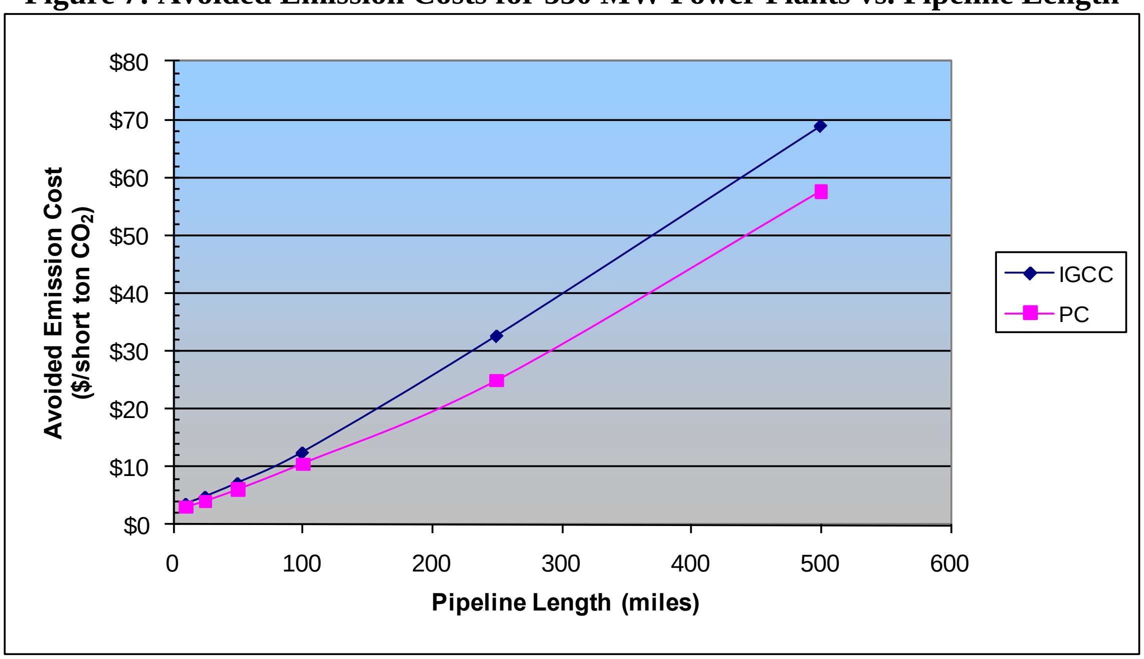
Figure 7: Avoided Emission Costs for 550 MW Power Plants vs. Pipeline Length



[4] Avoided cost calculations are based upon a levelized cost of electricity reported in Volume 1 of NETL's *Cost and Performance Baseline for Fossil Energy Plants* study. Electricity costs are levelized over a 30 year period, utilize a capital charge factor of 0.175, and levelization factors of 1.2022 and 1.1568 for coal costs and general O&M costs, respectively [3].

Addressing our initial topic, we see that our T&S avoided emission cost of \$5 to \$10 per short ton of CO_2 is associated with a pipeline length of 30 to 75 miles for the reference reservoir and our IGCC reference plant, or 50 to 95 miles for our PC reference plant. The T&S removal cost of \$5 to \$10 per short ton of CO_2 is associated with a pipeline length of 40 to 100 miles for an IGCC and 40 to 115 for a PC plant. Both of these ranges apply to the reference reservoir found in Table 1.

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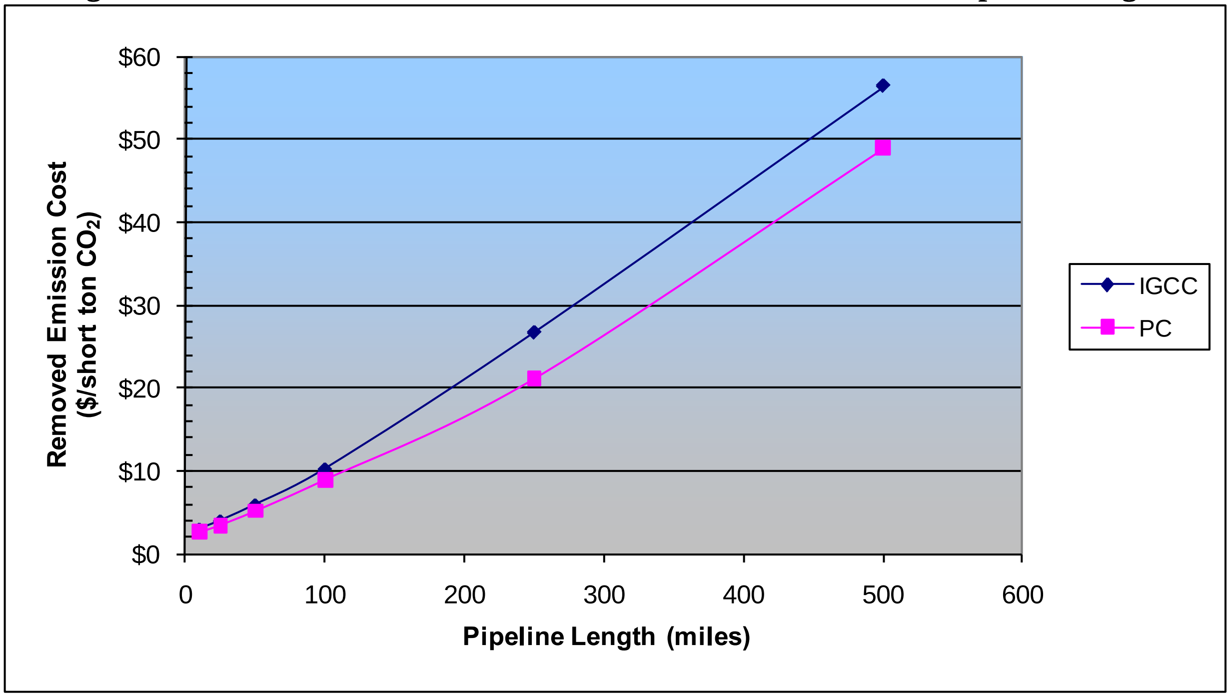
Figure 8: Removed Emission Costs for 550 MW Power Plants vs. Pipeline Length



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Conclusions

- T&S avoided emission cost of \$5 to \$10 per short ton of CO_2 is associated with a pipeline length of 30 to 75 miles for our reference IGCC plant and the reference reservoir found in Table 1, or pipeline lengths of 50 to 95 miles for the PC plant.

- T&S removed emission cost of \$5 to \$10 per short ton of CO_2 is associated with a pipeline length of 40 to 100 miles for an IGCC and 40 to 115 for a PC plant. Both of these ranges apply to the reference reservoir found in Table 1.

- Capital costs associated with CO_2 storage become negligible compared to the cost of transport (i.e. pipeline cost) for pipelines of 50 miles or greater in length.

- Transport and storage operating costs are roughly equivalent for a 25 mile pipeline but transport constitutes a much greater portion of operating expenses at longer pipeline lengths.

- Transport capital requirements outweigh storage costs, independent of CO_2 flow rate, at a pipeline length of 50 miles and the reference reservoir.

- Operating expenses associated with storage approach transport operating costs for flow rates of 25,000 short tons of CO_2 per day at a 50 mile pipeline length.

Future Work

This paper has identified a number of areas for investigation in future work. These include:

- Investigation into the apparent wide variability in site characterization and evaluation costs, including a sensitivity analysis to be performed to determine the sensitivity of overall project costs across the reported range of values.

- Continued research into liability costs and requirements.

- Further evaluation and sensitivity analysis into the number of land-owners pore space rights will have to be acquired from for a given sequestration project.

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Carbon Capture Research

Before carbon dioxide (CO2) gas can be sequestered from power plants and other point sources, it must be captured as a relatively pure gas. On a mass basis, CO2 is the 19th largest commodity chemical in the United States, and CO2 is routinely separated and captured as a by-product from industrial processes such as synthetic ammonia production, H2 production, and limestone calcination.

Existing capture technologies, however, are not cost-effective when considered in the context of sequestering CO2 from power plants. Most power plants and other large point sources use air-fired combustors, a process that exhausts CO2 diluted with nitrogen. Flue gas from coal-fired power plants contains 10-12 percent CO2 by volume, while flue gas from natural gas combined cycle plants contains only 3-6 percent CO2. For effective carbon sequestration, the CO2 in these exhaust gases must be separated and concentrated.

CO2 is currently recovered from combustion exhaust by using amine absorbers and cryogenic coolers. The cost of CO2 capture using current technology, however, is on the order of $150 per ton of carbon - much too high for carbon emissions reduction applications. Analysis performed by SFA Pacific, Inc. indicates that adding existing technologies for CO2 capture to an electricity generation process could increase the cost of electricity by 2.5 cents to 4 cents/kWh depending on the type of process.

Furthermore, carbon dioxide capture is generally estimated to represent three-fourths of the total cost of a carbon capture, storage, transport, and sequestration system.

The program is pursuing evolutionary improvements in existing CO2 capture systems and also exploring revolutionary new capture and sequestration concepts. The most likely options currently identifiable for CO2 separation and capture include:

- Absorption (chemical and physical)
- Adsorption (physical and chemical)
- Low-temperature distillation
- Gas separation membranes
- Mineralization and biomineralization

Opportunities for significant cost reductions exist since very little R&D has been devoted to CO2 capture and separation technologies. Several innovative schemes have been proposed that could significantly reduce CO2 capture costs, compared to conventional processes. "One box" concepts that combine CO2 capture with reduction of criteria pollutant emissions are being explored as well.

Examples of activities for this program element include:

- Research on revolutionary improvements in CO2 separation and capture technologies
  - new materials (e.g., physical and chemical absorbents, carbon fiber molecular sieves, polymeric membranes);
  - oxygen-enhanced combustion approaches;
- Development of retrofittable CO2 reduction and capture options

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for existing large point sources of $CO2$ emissions such as electricity generation units, petroleum refineries, and cement and lime production facilities;

- Integration of $CO2$ capture with advanced power cycles and technologies and with environmental control technologies for criteria pollutants.

Technical challenges facing the transport of anthropogenic CO_2 by pipeline for carbon capture and storage purposes

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With the support of

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GdF Suez, National Grid, Salzgitter Mannesmann Forschungsinstitut
and the European Pipeline Research Group (EPRG)

Abstract

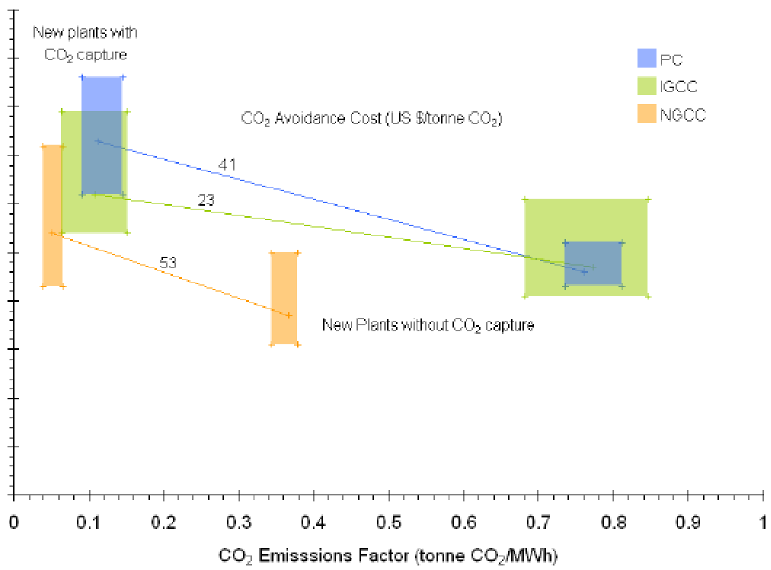
The massive effort required to reduce emissions of CO_2 to atmosphere will inevitably require the roll out of Carbon Capture and Storage (CCS) at many existing and new power stations. Considerable effort has been focused on capture or storage, while only little effort has been directed towards filling the existing gaps of knowledge in CO_2 handling and transportation in a safe, efficient and convenient manner. CO_2 pipelines have been in operation in USA, Europe and North Africa since the 1980's; however anthropogenic carbon dioxide transport by pipeline brings with it new challenges due to the effects of different impurities coming from flue gases. It cannot be assumed that knowledge regarding the transportation of pure CO_2 for Enhanced Hydrocarbon Recovery (EHR) can be transferred to the design challenges presented by the transportation of anthropogenic carbon dioxide mixtures through densely populated regions of Europe.

This paper will address the Scope of Work of SARCO2 Project "Requirements for Safe and Reliable CO_2 Transportation Pipeline", presented as a research proposal from an integrated team of pipe producers (Europipe, Salzgitter Mannesmann Line Pipe, V&M Deutschland, Corinth Pipeworks), energy companies (eni, GdF Suez, National Grid) and research centres (Centro Sviluppo Materiali, Salzgitter Mannesmann Forschungsinstitute) with the support of EPRG. The aim is to develop specific design requirements and steel pipe performance criteria for anthropogenic carbon dioxide transportation pipeline systems, as a first step towards creating European Guidelines for the safe design and operation of anthropogenic CO_2 pipeline networks. The most relevant technical topic is the improvement of know-how and experimental data on fracture control initiation (the strong cooling effect due to a leaking defect can cause a brittle/ductile transition) to prevent an unstable long running shear propagation event by developing crack arrest design tools (also including composite reinforced pipes). Furthermore, information and data on anthropogenic carbon dioxide dispersion from a suddenly-fractured pipeline and from leaking vessels will be collected. This last "by product" result will increase the available public data for validating existing models for assessing carbon dioxide release (the size of the affected area and the consequences) in the unlikely event of a leak or rupture. This breakthrough approach will add to the knowledge base through extensive and expensive full scale testing in a manner that has never been performed before.

1. Introduction

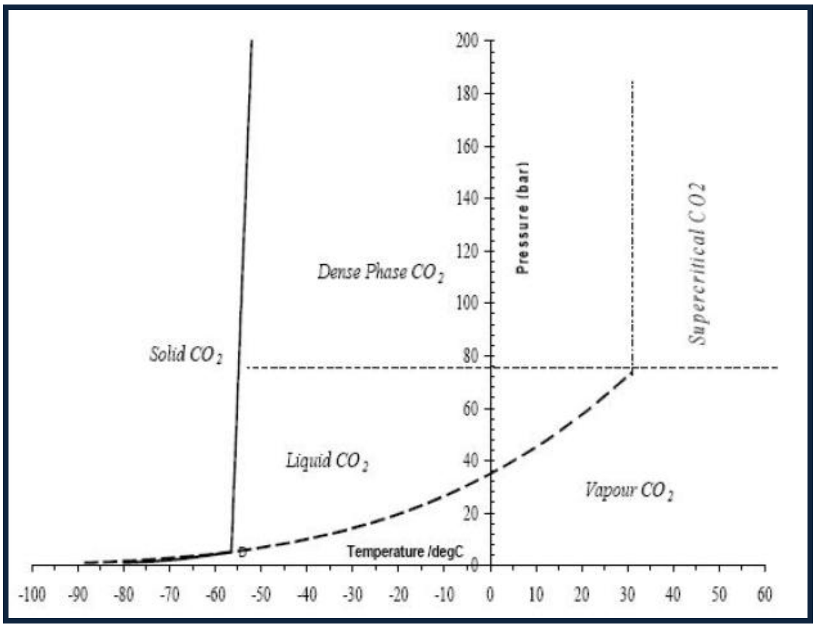
Carbon Capture Transportation and Sequestration (CCTS) is a mandatory approach for reducing fossil fuel power plant emissions down to acceptable levels, and technical solutions for capture and sequestration of anthropogenic CO_2 have to be found urgently. This is in accordance with the European Union Renewable Energy Directive that aims to pave the way for a 20% cut in greenhouse gas emissions by 2020, the so-called *"20:20:20 Plan".* For example, Figure 1 shows that the use of CCTS technology could allow a reduction in the CO_2 emission to atmosphere from 0.4-0.8 ton/MWh to 0.05-0.12 ton/MWh /1//2//3/. However, the issue of anthropogenic carbon dioxide transportation from the energy plant to the remote sequestration area represents a fundamental concern regarding the feasibility of applying CCTS technologies. /4//5/.

Figure 1 Ranges for the COE and CO2 emissions factor for different power plant technologies with and without capture based on current technologies./3/



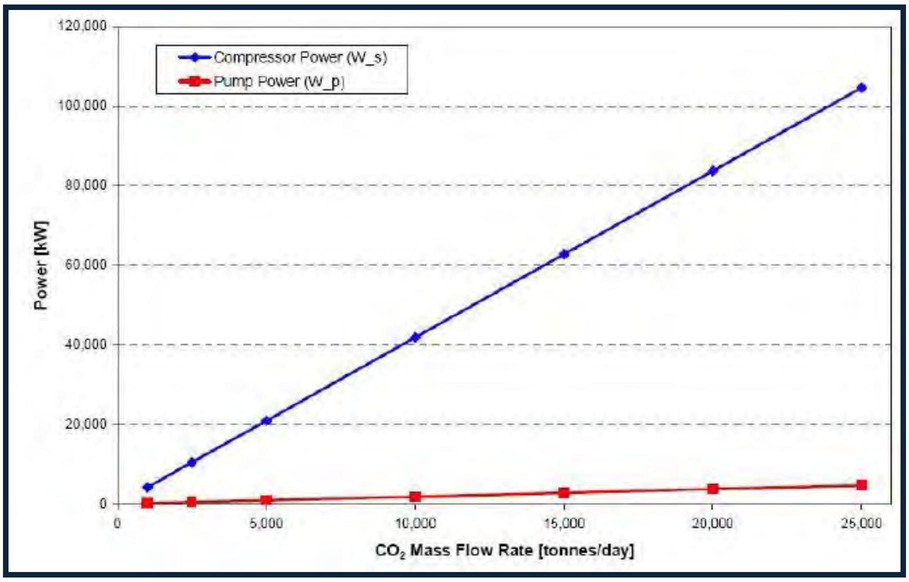
In this scenario pipelines (both onshore and offshore) can represent a very promising solution, as they can efficiently transport supercritical or dense phase CO_2 (see Fig 2) and most of the know-how already available from natural gas transportation system could be used. As it can be noted from Figure 3 below, the power requirement of compressors is much greater than the power requirement of pumps. So, if carbon dioxide were transported in the gas phase, a huge amount of power would be required. Furthermore considering the low viscosity of the supercritical phase, it is easy to understand why carbon dioxide is transported in this way. This means that pure CO_2 has to be transported at a pressure above 8 MPa (at room temperature) to avoid phase changing due to temperature fluctuations (which, of course, cannot be controlled quantitatively and depend on the seasons and the region in which the pipeline is operating).

Figure 2. Pure Carbon dioxide phase diagram



Large diameter pipelines have already been used in USA, Canada, Algeria and Norway, mainly for pure CO_2 in EHR (Enhanced Hydrocarbons Recovery) applications. One example is the *Cortez Pipeline* for the transportation of CO_2; this pipeline, which has a total length of 800 km, a diameter of 30" and a maximum service pressure of 17.8 MPa, has been operated since 1984 in the USA by Kinder Morgan, with a capacity of transport of about 20 Mton/year.

Figure .3 Power requirement for compression or pumping.



Nevertheless, even if CO_2 transportation by pipeline could be regarded as mature (above 7000 km of pipelines have already been laid or are planned worldwide), the accumulated operating experience and guidelines are absent or inadequate for European scenarios. The existing CO_2 pipelines are largely located in remote areas (in particular in the South-West of USA, Texas and New Mexico) where the population density is very low and at the same time the probability of external mechanical interference (one of the most frequent causes of failure in buried pipelines) is lower than the average value recorded in Europe over the last five years (about 0,2 leak events for 1000 km of line per year according to EGIG). Moreover a significant amount of this know-how has been developed on the transportation of pure CO_2, and it cannot be directly applied to anthropogenic CO_2 transportation. The presence of impurities (such as H_2S, SO_2, CH_4, H_2,) and water has a significant impact on the physical properties of the CO_2, particularly those affecting transportation (recompression distances), operation & maintenance (corrosion and stress corrosion control) and design (fracture control and corrosion/stress corrosion prevention), /6/ /7/ /1/.

Furthermore networks connecting multiple anthropogenic carbon dioxide capture and sequestration areas need proper specification. The major challenges for these infrastructures can be summarized in the following four key issues:

- ✓ engineering design of pipelines from the integrity long term point of view,
- ✓ supply and demand balance,
- ✓ overall cycle cost and capacity,
- ✓ regulatory, financing, legal issues, codes/standards.

Regarding this last point, the review of existing codes and standards dedicated to the transport of fluids in pipelines has revealed that suitable guidelines for anthropogenic CO_2 transportation are not available. Codes as IP6, BS EN 14161, BS PD 8010, DNV OS-F101 and ASME B31.8 may be applicable to pipelines transporting CO_2, while ASME B31.4 is applicable to liquid hydrocarbons, but none of these explicitly include transportation of anthropogenic CO_2 in the supercritical/dense phase. Up to now a specific design or fitness-for-service procedure for CO_2 pipelines within the international regulatory frameworks does not exist. DNV has recently proposed a new Recommended Practice (DNV-RP J 202 "Design and Operation of CO2

Pipelines”) as conclusion of the first phase of a Joint Industry Project (“CO_2 PipeTrans-phase 1”) aimed at assessing the possibilities of updating the DNV-OS-F101 code for offshore transportation of CO_2.

All these key issues will impact on the general development and in-field application of anthropogenic CO_2 capture and storage technologies, particularly in Europe. The lack of CCTS operational know-how, combined with the uncertain long-term financial environment, the regulatory constraints and the acceptability and capacity of selected locations, affect the commercial development of large-scale CCTS pipeline infrastructures/17/. Efforts to increase the know-how on the integrity of anthropogenic carbon dioxide pipelines and their management will help to reduce these barriers and allow initiation of significant investment in pipeline networks.

To address this lack of know-how, many research initiatives have been launched in Europe in recent years, without and with the contribution of European Community (E.C.).

Outside the E.C., but closely connected with several European energy industry companies, one project about to be launched is DNV - JIP proposal (“CO_2PIPETRANS – Phase 2”). This project is specifically aimed at defining the toughness requirements, material compatibility and corrosion behaviour of steel pipes, as well as providing data enabling the management of dense phase CO_2 releases. . Results from this JIP will be used to update the existing DNV Recommended Practice DNV-RP-J202 “Design and Operation of CO_2 Pipelines”, April 2010. Moreover a European consortium involving the electricity and gas supplier National Grid, the energy providers E-On Ruhrgas, GDF Suez and eni S.p.A. and the three pipe manufactures Europipe GmbH, V&M Deutschland GmbH and Salzgitter Mannesmann Line Pipe GmbH has been formed with the aim of launching a JIP to define the requirements for avoiding corrosion and stress corrosion issues in anthropogenic CO_2 transportation pipeline systems. Other initiatives in progress or about to be launched have the following aims:

- ✓ to study the release of large quantity of pure and/or anthropogenic CO_2 from a small-medium diameter pipeline.
- ✓ to collect and produce experimental data about the decompression of CO_2 mixtures starting from supercritical conditions, to provide a better definition of the driving force during a running ductile fracture propagation event.

In parallel, but under the umbrella of European Community, in response to the FP7-ENERGY-Call at the end of 2008 three proposals focusing on specific aspects of transportation of CO_2, including ship transportation, have been accepted and are ongoing. The objectives of these projects are the following:

- ✓ Quantitative analysis of failure hazard release of next generation of CO_2 pipelines.
- ✓ Development of criteria for a safe marine transportation by shipyard.
- ✓ Development of criteria for the development of an integrated infrastructure for CO_2 transportation and storage.

Besides, within the framework of the Zero Emissions Platform (ZEP), Task Force Technology, a group of experts from European industries concerned with carbon dioxide transport in the context of Carbon Capture and Storage, has worked to identify the key cost elements and to forecast the long term costs of CO_2 transport by ship, onshore and offshore pipelines, both as pressurized and liquefied gas. The first results of this *"state of art"* study have been presented during the spring 2010 ZEP meeting in Copenhagen and the full results will available in a short time.

Finally, the Research Funding Coal and Steel (RFCS) of the European Commission has recently accepted the **SARCO2** proposal *"REQUIREMENTS FOR **SA**FE AND **R**ELIABLE **CO_2** TRANSPORTATION PIPELINE".* This research project involves an integrated team of pipe producers (Europipe, Salzgitter Mannesmann Line Pipe, V&M Deutschland, Corinth Pipeworks), energy companies (eni S.p.A, GdF Suez, National Grid) and research centres (Centro Sviluppo Materiali, Salzgitter Mannesmann Forschungsinstitut), with the support of EPRG (European Pipeline Research Group). The aim of the project is to contribute to the engineering design of pipelines from the long-term integrity point of view, through the development of specific requirements and design criteria for anthropogenic carbon dioxide transportation using steel pipeline systems. This paper describe both the scope of the work of SARCO2 project and the approach employed to achieve the expected results.

2. Technical challenges for a safe design of CO2 transportation pipelines

The natural gas industry has extensive experience on pipeline transportation. However, CO_2 (and in particular anthropogenic CO_2) shows significantly different physical properties and behaviour in the pipeline transportation process. Compared to natural gas, the most relevant differences regarding structural integrity issues are:

- ✓ Higher susceptibility to long-running ductile fracture propagation than natural gas pipeline operating at comparable material usage working conditions, as the CO_2 decompression curve is more severe and as a consequence the driving force is stronger and the crack arrest conditions can be reached only using steel pipes with very high toughness, or using external mechanical devices (Crack Arrestors) and/or using innovative ultra high "equivalent toughness" reinforced pipes. Figure 4 shows, as an example, two possible ductile fracture propagation scenarios for a gas pipeline involving low and high numbers of pipes, while Figure 5 shows a composite crack arrestor before and after the test.
- ✓ The high likelihood to have lower temperatures during service operation (as during line venting down to -20°C) or in case of a unlikely event of a leakage (down to T = -80°C) due to the significant Joule Thomson cooling effect (as indicated by H. Mahgerefteh, /15) which results in pipe material toughness decreasing.
- ✓ Increased pipe wall corrosion and/or stress corrosion susceptibility when free water phase is present within the CO_2 mixture.

Regarding the first point, it is worth noting that the decompression behaviour of CO_2 leads to more severe crack propagation driving force compared to natural gas; this has been known since the first studies carried out by Battelle 30 years ago /8/, /9/, /10/ and has recently confirmed by the desk studies of Cosham, and Eiber /1/, /7/. These tests and studies highlight the key role of impurities in the anthropogenic CO_2 mixture, and their detrimental effect on crack propagation driving force /7/ /16/.

Figure 4: Full scale propagation tests with long and short running fracture on a

natural gas pipeline section (CSM archives)

In the possible event of a leakage, the sudden pressure loss causes a considerable temperature drop in the affected area; as a consequence the pipeline steel may reveal local brittle behaviour and also experience high local residual stress, which can encourage the transition from leak to break and the onset of running fracture propagation. There is also the possibility that lower temperatures will arise during service operation (as during line venting down to -20°C) or in the unlikely event of a leakage (down to T = -80°C) due to significant Joule Thomson cooling effects (as indicated in work of H. Mahgerefteh,/15/).

Figure 5: Composite crack arrestor for gas pipelines before and after a fracture propagation test.

Hence there is a potential risk that a leak may evolve into a break for a CO_2 pipeline. This forces the definition of more stringent requirements in terms of minimum service temperature for both base material and welded joints in anthropogenic CO_2 pipeline compared to those in natural gas pipelines (-5°C to -10°C typically for the onshore natural gas European pipelines grid) down to -25°C to -30°C (used for the CO_2 "Cortez" pipeline constructed recently in USA). These lower design service temperatures reflect in more demanding requirements for welding consumables, and also the need to develop specific Welding Procedure Specifications (WPS) to guarantee girth welded joints with good toughness at the low service temperatures.

Laboratory studies utilising CO_2 at high pressure and corresponding field experiences suggest that corrosion of carbon steel in pure dry CO_2 is negligible. But it is well known that at low to medium CO_2 partial pressure severe corrosion damage will occur if a water-enriched phase is present. Economical considerations in the power plant sequestration process require a minimum degree of humidity. Moreover in the presence of gases like H_2S, CO, SO_x, NO_x and probably even $H_{2,}$ corrosion phenomena like hydrogen assisted cracking, stress corrosion cracking and corrosion fatigue can arise. The likelihood and severity of these different corrosion mechanisms depend on several parameters. Data concerning these effects are non-existent /11//12//13/ (as mentioned above, this knowledge gap will be addressed by the JIP that has been launched in Europe in the summer of 2010).

The consequences and hazards of CO_2 release are somewhat different from a natural gas pipeline. As CO_2 is heavier than air it will accumulate in depressed surroundings. Unlike natural gas it is not explosive or inflammable, but nevertheless it can cause choking and asphyxia depending on the gas concentration and time of exposure; 4-6 % (vol/vol) can be dangerous for a person in a few minutes and 17-20 % (vol/vol) can result in death. Though existing work concerning the failure of gas pipelines suggests that impacts from CO_2 pipeline accidents may be less severe than with natural gas or liquid pipelines, nevertheless data about the release of large amounts of CO_2 are not available, particularly for European population densities which are higher than those in the USA /14/, /15//16/. So, full-scale tests allowing for representative 'in-service' dispersion measurements will provide valuable and essential data.

3. Description of the SARCO2 – RFCS Project.

3.1 Aim of initiative

The general aim of SARCO2 project is to give a contribution to "engineering design of pipelines from the long-term integrity point of view", through the development of the following actions:

- ✓ to generate reliable data for determining the feasibility of using steel pipeline systems for the transport of anthropogenic CO_2;
- ✓ to contribute to the future development of a guideline for safe design and operation of a CO_2 pipeline network in Europe;
- ✓ to develop a specific know-how to be used in order to verify the possibility of employing existing pipeline systems for the safe transport of CO_2.

The use of oil&gas pipeline material and construction approaches (based on conventional pipeline steel grade L415M/Q – L485M/Q according to ISO 3183 and EN 10208 part 2 and EN 1594) and the incorporation of contemporary approaches with crack arrestor solutions will be pursued in order to meet the stringent structural integrity demands for transportation of anthropogenic CO_2. In particular this project is focused on the previously identified major technical challenges that could limit the wider deployment of CO_2 pipelines technology in Europe, and addresses:

- ✓ Definition of toughness requirements to control initiation (leak vs. break) and long-running ductile fracture propagation using large and full scale test on real sections of pipeline.
- ✓ Collection of experimental data related to the release of large quantity of CO_2 during a representative pipeline failure event, both during a leakage and

during a long-running ductile fracture propagation.

Moreover in regard to the fracture event specific goals of this project will be also:

- ✓ Development of crack arrest design tools in order to guarantee safe large diameter CO_2 pipeline and qualification of ultra high "equivalent toughness" reinforced composite pipes to achieve reliable designs of CO_2 pipelines with very severe operational conditions.
- ✓ Collection and analysis of existing and available data and knowledge about the corrosion and/or stress corrosion resistance of both pipe body and welded zone working in the anthropogenic CO_2 environment. Improvement of this know-how database through specific laboratory-based activities.

3.2 Overview of experimental activities

The experimental and analytical activities will be developed following three different lines related to the integrity and reliability of an anthropogenic CO_2 pipeline:

- ✓ Crack initiation/leak event, with the release of a large quantity of anthropogenic CO_2 during the leak failure of a pipeline,
- ✓ Instable ductile fracture propagation event, with the release of very large quantity of anthropogenic CO_2 in very short time during a running ductile fracture failure event
- ✓ Corrosion and stress corrosion events.

To study these specific issues, laboratory testing accompanied by full-scale in-service fracture testing will be performed. The SARCO2 project aims to perform challenging full scale fracture tests for the first time in Europe on CO_2 pipelines. These full scale tests will provide vital data which is essential for the development and verification of adequate approaches and modelling. They will also enable measurements of in-field real-scale dispersion behaviour of anthropogenic CO_2 which will contribute to the development of realistic hazard scenarios.

For the full scale test activities, CSM has specifically devoted a large area of its "Remote Full Scale Testing Laboratory" located in Sardinia, within the Perdasdefogu Military Firing Range to the Carbon Dioxide Full Scale Facility; this was necessary due to the tight safety measures required when handling large amounts of carbon dioxide.

3.3 Crack initiation / leak event

Within the SARCO2 project, full-scale *Leak Before Break* tests will be performed on single instrumented pipes (length of single pipe > 6m). For these tests pipes in L415M/Q – L485M/Q steel grade (according to ISO 3183 and EN 10208 part 2) with an external diameter in the range 8" – 16" and thickness 10 – 20 mm will be selected. The tests will be performed with different chemical compositions of anthropogenic CO_2 at an appropriate pipe usage factor.

All tested pipes will be instrumented to measure:

- ✓ pipe *internal pressure vs. time* using pressure transducers.
- ✓ the *internal and external temperature vs. time* of the pipe in the leak zone, using thermocouples.

Moreover the CO_2 temperature around the leak zone will be mapped versus time using a special thermo-video camera integrated with thermocouples. During these leak tests experimental data will be collected about the release under stable outflow conditions of CO_2 from the leakage; therefore a map of the *concentration of anthropogenic CO_2 vs. time* and *vs. distance and height* around the test pipe will be obtained.

All the above experimental data will be used to identify major factors affecting the evolution during time of a leak in the CO_2 pipeline and the possible occurrence of a break (that is full bore rupture) condition. Then, on the basis of this data as well as experience and results from fracture mechanical models available in the public domain, an updated *Leak vs. Break* model to be used for CO_2 gas pipeline will be developed, also making use of Finite Element analysis with devoted commercial FE codes.

Such a model is intended for use in pipeline design to determine the toughness requirements (in terms of both ductile/brittle transition temperature and shelf energy at service temperature) to prevent a break occurrence from a leak. Such a model could also be used for sensitivity analyses concerning the relative importance of different parameters (such as diameter and thickness of pipe, initial pressure, temperature and chemical composition of anthropogenic CO_2 etc), providing support to the general guidelines regarding this kind of failure.

3.4 Ductile fracture propagation event

Two full-scale fracture propagation tests will be conducted to study the crack arrest conditions and, in particular, to evaluate the toughness requirements to prevent long (more than one pipe) ductile fracture propagation initiated from an initial defect located in the pipe body. Generally, each test involves a minimum of five test pipes located in a test line including two external reservoirs with the same diameter of test pipes and a length of about six pipes to reproduce the same fluid dynamic conditions that exist in a real pipeline. Specific goals of these tests are:

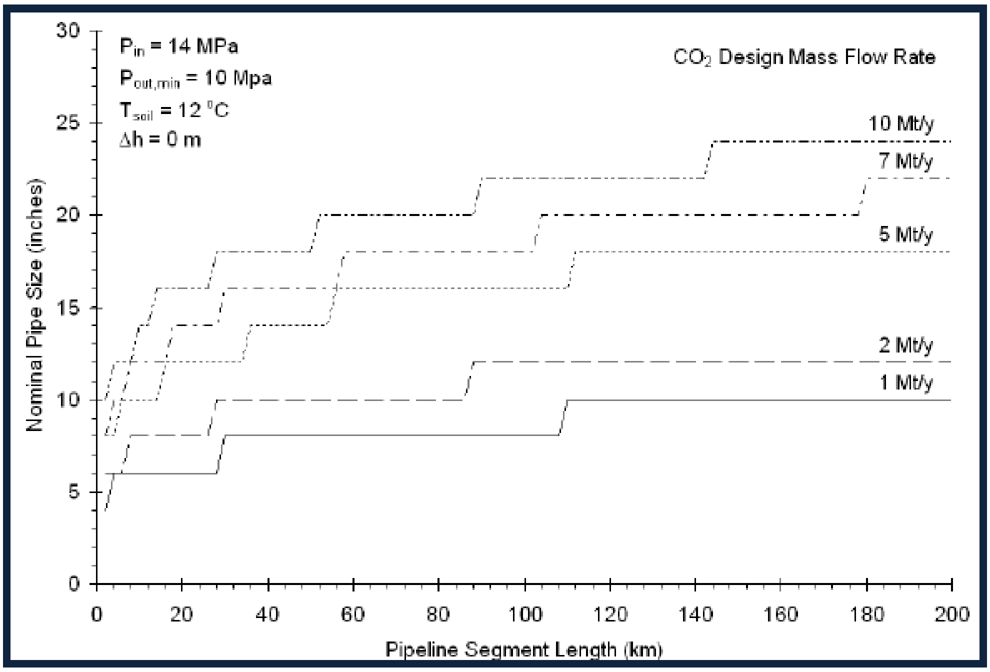
- ✓ evaluation of the ductile fracture propagation behavior using real-size anthropogenic CO_2 gas pipelines, to quantify the minimum pipe toughness requirements to achieve ductile crack arrest conditions; toughness will be expressed in terms of base material toughness and/or “equivalent toughness” in the case of crack arrestor device.
- ✓ study of the decompression behavior of CO_2 gas mixtures (anthropogenic CO_2) inside the line during the rupture event to evaluate the real crack driving force;

In accordance with the general aim of this project and the relevant numbers of parameters to be studied, the diameter of pipes will be the same for both tests while the chemical composition of the gas and/or service conditions (as usage factor i.e. pressure) will be changed. Provisionally, the diameter of the test lines has been fixed at 24“.

This diameter has been proposed on the base of two following considerations:

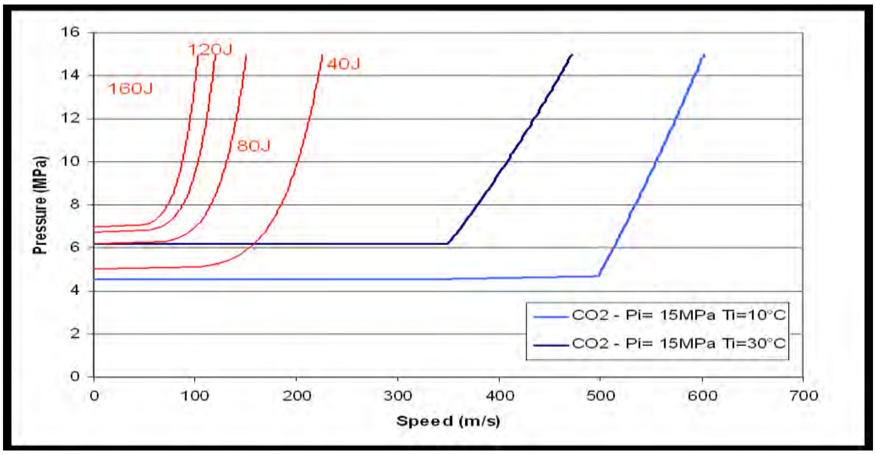
- ⇒ This is a diameter applicable for the transportation of quantities of CO_2/year of industrial interest (about 6 – 8 Mton/year). See Figure 6.
- ⇒ The diameter and the expected service conditions (pressure, temperature, etc) could potentially lead to a fracture propagation event.

Figure 6 Pipeline diameter as a function of length for several flow rates in Mt/y for *isothermal flow at 12°C./1/*



Regarding this last point, Figure 7 shows the arrest / propagation toughness condition (in terms of Charpy V shelf energy) calculated using the Battelle model coupled with the CSM decompression model (GASMISC), for a pipeline with diameter 24" and thickness of 14.11 mm at a service pressure of 15 MPa . It can be seen that the toughness arrest condition (for a temperature of about 30 °C) could be in a range of 80 -100J .

Figure 7: Arrest / propagation for a CO_2 pipelines on the base of Battelle model coupled with the decompression model of CSM, GASMISC



Anthropogenic CO_2 gas mixtures will be used and the specific instrumentation will include:

- ✓ Timing wires, to measure the crack speed during fracture propagation;

- ✓ Pressure transducers to measure the initiation pressure and internal gas decompression behavior during failure;
- ✓ Thermocouples to measure the temperature both of CO_2 and pipes.

Finally, to reproduce realistic operating conditions for pipelines, the test line will be buried at 1 m depth and the test will be performed at ambient temperature, about 10°C.

The general framework of the planned two full-scale CO_2 pipe burst tests is given below, although the final selection of test parameters will be made later on. The test parameters and layout proposed for the **first test** are as follows:

- ✓ Geometry of pipes: Diameter: 24”, Thickness: 12- 20 mm;
- ✓ Toughness Charpy V shelf energy in the range of 60 -200 J
- ✓ Grade of pipes: L415M/Q – L485M/Q steel grade (according to ISO 3183 and EN 10208 part 2);
- ✓ Type of Crack arrestors: Composite glass fiber crack arrestors;
- ✓ Type of pipes: SAWL and/or HFW and/or composite reinforced pipes;
- ✓ Gas composition: anthropogenic CO_2, with standard level of impurities (to be fixed);
- ✓ Test pressure: to be defined (i.e. usage factor);
- ✓ Test temperature: room underground temperature.
- ✓ Test line will be buried down to 1 m depth as in a real gas pipeline.

The test is designed to provide an arrest due to pipe body toughness properties, according to the best available know-how; in the case that such an approach dramatically underestimates the minimum toughness energy for having an arrest, external mechanical devices (that is crack arrestor and/or composite reinforced pipes) will be designed and adopted.

Test parameters and layout proposed for the **second test** are as follows:

- ✓ Geometry of pipes: Diameter: 24”, Thickness: 12 - 20 mm;
- ✓ Toughness Charpy V shelf energy in the range of 60 -200 J
- ✓ Grade of pipes: L415M/Q – L485M/Q steel grade (according to ISO 3183 and EN 10208 part 2);
- ✓ Type of Crack arrestors: Composite glass fiber crack arrestors;
- ✓ Type of pipes: SAWL and/or HFW and/or composite reinforced pipes;
- ✓ Gas composition: anthropogenic CO_2, with high level of impurities (to be fixed);
- ✓ Test pressure: to be defined (i.e. usage factor);
- ✓ Test temperature: underground temperature.
- ✓ Test line will be buried down to 1 m depth as in a real gas pipeline.

In parallel to the above full scale running ductile fracture tests, experimental data will be acquired regarding the release of anthropogenic CO_2 from the fractured zone (up to a proper distance) of the test pipeline section will be acquired. The specific goal of this task is to collect experimental data about the gas dispersion map in the region surrounding the test lines during both tests for an appropriate time period. In these tests, unlike the release of CO_2 from leakage, a realistically large quantity of anthropogenic CO_2 will be released in very short time.

3.5 Corrosion and stress corrosion events

Laboratory activity will be dedicated towards improving the experimental understanding by increasing the amount of experimental data. The test program will characterize the corrosion and stress corrosion behavior of materials from the welded girth joints developed and used in this project. Autoclave testing will allow the assessment of corrosion rates and risk of localized corrosion in comparison to the base materials. The test program will include different combinations of weld technologies, consumables and base materials.

Tests planned are:

- ✓ *Corrosion tests.* Autoclave corrosion testing under stagnant conditions and simulated flow in rotating cage and rotating disc test setups by using various chemical compositions of anthropogenic CO_2. The transfer and verification of the usability of corrosion inhibition concepts will be updated based on results from the above tests and from a state-of-the art-review.
- ✓ *Stress corrosion tests at constant stress level.* SSC four-point-bend tests of the selected welded joints under different H_2S partial pressures, using gas mixtures of H_2S in CO_2 under test conditions defined in EFC 16.
- ✓ *Stress corrosion tests at variable stress level.* Slow-strain-rate (SSR) and cyclic SSR tests, simulating realistic transport environment conditions (anthropogenic CO_2 in dense phase and supercritical conditions) and pressure changes. The chemical composition of the anthropogenic CO_2 will be fixed in accordance with those used in the other work packages.

4. Expected results

The deliverables from this project will be the availability of:

1. Criteria and know-how for the identification of the minimum pipe property requirements for the design of safe and reliable anthropogenic CO_2 transportation pipelines. These will include, in particular, requirements for corrosion and toughness of both pipes body and welded joints to control the fracture events (both crack initiation and fracture propagation).
2. Validation of technological options both for composite crack arrestors for large diameter anthropogenic CO_2 pipelines and for composite reinforced pipes.
3. Collection of experimental data related to the release of large quantity of CO_2 during a relevant pipeline failure, both during a leakage and during a long-running ductile fracture propagation.

In parallel the wide transferability of the results will be ensured by the involvement of the various industrial partners, among them EPRG. Several EPRG members are directly involved in the operation and management of the majority of the European pipeline network and they will guarantee the applicability and rapid uptake of the results obtained.

At the conclusion of the project EPRG, with the substantially contribution of CSM, will organize a Workshop in Sardinia-Pula-Perdasdefogu (test site of the full-scale pipe burst tests) to increase the awareness of the international Carbon Capture Transportation and Sequestration technology community on the anthropogenic CO2 pipeline transportation issue and work of the Project. This Workshop will be open to specialists only and will focus on promoting a discussion about the results obtained and the remaining open issues, with a view to obtaining consensus on the use of the developed understanding and know-how.

The results from this project will make a significant contribution towards developing European Guidelines for the safe design and operation of anthropogenic CO_2 pipelines. At the same time they will support political approaches for the safe and reliable supply of energy to Europe. Hence, the results of this activity will contribute to the acceptability of CO_2 capture, transportation and storage (CCTS) in Europe as a key determining factor both to reduce the impact of greenhouse gases and to achieve the 20-20-20 targets agreed by the European Parliament and Council and law of the European Union in June 2009.

5. Acknowledgements

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8. Furnaces / Process Heaters

Approximately 30% of the fuel used in the chemical industry is used in fired heaters. The average thermal efficiency of furnaces is estimated at 75-90% (Petrick and Pellegrino, 1999). Accounting for unavoidable heat losses and dewpoint considerations the theoretical maximum efficiency is around 92% (HHV) (Petrick and Pellegrino, 1999). This suggests that typical savings of 10% can be achieved in furnace and burner design, and operations. In the following section, various improvement opportunities are discussed, including improving heat transfer characteristics, enhancing flame luminosity, installing recuperators or air-preheaters and improved controls. New burner designs aim at improved mixing of fuel and air and more efficient heat transfer. Many different concepts are developed to achieve these goals, including lean-premix burners (Seebold et al., 2001), swirl burners (Cheng, 1999), pulsating burners (Petrick and Pellegrino, 1999) and rotary burners (U.S. DOE-OIT, 2002c). At the same time, furnace and burner design has to address safety and environmental concerns. The most notable is the reduction of NOx emissions. Improved NOx control will be necessary in many chemical industries to meet air quality standards.

Heat generation. In heat generation, chemical or electrical energy is converted into thermal energy. A first opportunity to improve the efficiency of heat generation is to control the air-to-fuel ratio in furnaces. Badly maintained process heaters may use excess air. This reduces the efficiency of the burners. Excess air should be limited to 2-3% oxygen to ensure complete combustion. Typical energy savings of better controlled air to fuel ratios vary between 5 and 25% (U.S. DOE-OIT, 2004c). The use of up-to-date exhaust gas oxygen analyzer can help to maintain optimal air-to-fuel ratios. At the Deer Park facility of Rohm and Haas, old exhaust oxygen analyzers resulted in delayed reading and made it more difficult to accurately monitor combustion conditions. Installation of three new analyzers in the furnace ducts resulted in real-time readings of oxygen levels and better process control (U.S. DOE-OIT, 2006d). Typical payback times of projects aiming to reduce combustion air flows by better control are around 6 months or less (IAC, 2006).

In many areas new air quality regulation will demand industries to reduce NOx and VOC emissions from furnaces and boilers. Instead of installing expensive selective catalytic reduction (SCR) flue-gas treatment unit’s new burner technology allows to reduce emissions dramatically. This will result in cost savings as well as help to decrease electricity costs for the SCR. In a plant-wide assessment of a Bayer Polymers plant in New Martinsville, West Virginia (U.S. DOE-OIT, 2003d), the replacement of natural gas and hydrogen fuelled burners with efficient low NO_x design burners was identified as a project that could result in 2% efficiency improvements saving 74,800 MMBtu per year and annual CO_2 emission reductions of 8.46 million pounds. Estimated pay-back time for the project was 13 months at total project costs of $ 390,000. Efficient use of existing burners can also help to save energy and reduce NO_x emissions. In an energy-efficiency assessment of the Anaheim, California site of Neville Chemical Company (U.S. DOE-OIT, 2003e), a potential project was identified in which only a single natural gas fuelled incinerator (instead of the two operated) can be used to incinerate Volatile Organic Compounds (VOCs). This would result in energy savings of 8 TBtu per year. Project costs were estimated at $57,500 with a payback period of 1.3 years.

Heat transfer and heat containment in heaters. Improved heat transfer within a furnace, oven or boiler can result in both energy savings and productivity gains. There can be several ways to improve heat transfer such as the use of soot blowers, burning off carbon and other deposits from radiant tubes and cleaning the heat exchange surfaces. Typical savings are 5-10% (U.S. DOE-OIT, 2004c). Ceramic coated furnace tubes can improve heat transfer of metal process tubing, while stabilizing the process tube's surface. They can improve energy efficiency, increase throughput or both. Increased heat transfer is accomplished by eliminating the insulating layers on the fire-side of process tubing that form during operation. Applications in boilers and petrochemical process units have shown efficiency improvements between 4% and 12% (Hellander, 1997). Heat containment can be improved by numerous measures, including reducing wall heat losses (typical savings 2-5%), furnace pressure control (5-10%), maintenance of door and tube seals (up to 5%), reducing cooling of internal parts (up to 5%) and reducing radiation heat losses (up to 5%). Typical payback times of project aiming to reduce heat losses and improved heat transfer are between 3 months and 1 year (IAC, 2006).

Flue gas heat recovery. Reducing exhaust losses (e.g. by the measures described above) should always be the first concern in any energy conservation program. Once this goal has been met, the second level should be considered – recovery of exhaust gas waste heat. Use of waste heat to preheat combustion air is commonly used in medium to high temperature furnace. It is an efficient way of improving the efficiency and increasing the capacity of a process heater. The flue gases of the furnace are used to preheat the combustion air. Every 35°F drop in the exit flue gas temperature increases the thermal efficiency of the furnace by 1% (Garg, 1998). Typical fuel savings range between 8 and 18%, and is typically economically attractive if the flue gas temperature is higher than 650°F and the heater size is 50 MMBtu/hr or more (Garg, 1998). The optimum flue gas temperature is also determined by the sulfur content of the flue gases to reduce corrosion. When adding a preheater the burner needs to be re-rated for optimum efficiency. Energy recovery can also be applied in catalytic oxidizers used to reduce volatile organic compound (VOC) emissions, e.g. via a regenerative heat exchanger in the form of a ceramic packing (Hydrocarbon Processing, 2003).

Heat from furnace exhaust gases or from other sources (discussed in Chapter 9) can also be used in waste heat or quench boilers to produce steam (discussed in Chapter 7) or to cascade heat to other applications requiring lower temperature heat as part of the total plant heat demand and supply optimization (see also Chapter 9 on process integration). Recovering thermal energy in the form of steam from incineration of waste products should be considered carefully. Because a waste stream is used, the stream will have variations in contaminant and component concentrations which influence to load on the boiler. Also, the contaminants might create acid gases causing corrosion problems for the boiler. These aspects should be taken into account in designing waste heat boilers (Ganapathy, 1995).

The benefits from heat recovery projects have been shown in various case studies. In an energy-efficiency assessment of the 3M Hutchinson, Minnesota, facilities, heat recovery from thermal oxidizers in the form of low-pressure steam was identified as a project that could save 210,000 MMBtu of fuels (U.S. DOE-OIT, 2003f). Project capital costs are $913,275 with avoided first year energy expenses of $772,191. In an audit of the W.R. Grace facility in

Curtis Bay, Baltimore, Maryland, a project was identified that uses flue gas heat in an air-to-water heat exchanger for fresh water heating, reducing the original steam demand for heating this water by 31%. Capital costs for this project are estimated at $346,800 with a relatively long payback period of 5.3 years (U.S. DOE-OIT, 2003g). In a project in the UK, heat recovery from an incinerator via a run-around coil system yielded energy savings of 9 TBtu per year with a payback time of 1.5 years (Best Practice Programme, 1991). Heat recovery from the SO_2 containing gases of a sulphur burning process in a sulphonation plant in Norway resulted in energy savings of 4,800 MWh per year (CADDETT, 2000b). Investment costs were $800,000 and the simple payback time of the project 6 years.

Others – controls, maintenance and electric heaters. Energy losses can also be reduced via improved process control. Improved control systems can help to improve aspects such as material handling, heat storage and plant turndown. Typical savings of improved control systems can be in the range of 2-10% (U.S DOE-OIT, 2004c). A relatively small part of the heating requirements in the chemical industry is supplied by electrically heated devices. Still, electric heaters account for approximately 3% of the electricity use of the chemical industry (U.S. DOE-OIT, 2006a). Not in all cases, electric heating is the right choice (Best Practice Programme, 2001) and in a number of cases, improvements are possible. For example, in an energy-efficiency assessment of the Anaheim, California site of Neville Chemical Company (U.S. DOE-OIT, 2003e), a potential project was identified in which electric heaters are to be replaced with a natural-gas fired heat fired system, using 557 MMBtu per year, but replacing 114,318 kWh of electricity. Project costs for the project were estimated at $6,100 with a payback time of 0.9 years. In an assessment of a Formosa Plastics Corporation polyethylene plant (U.S. DOE-OIT, 2005a), improvement of an electrically heated extruder was identified as a project that could result in electricity savings of 1,488,000 kWh annually, resulting in annual cost savings of $59,520. The estimated payback time for the projects was 0.1 year.

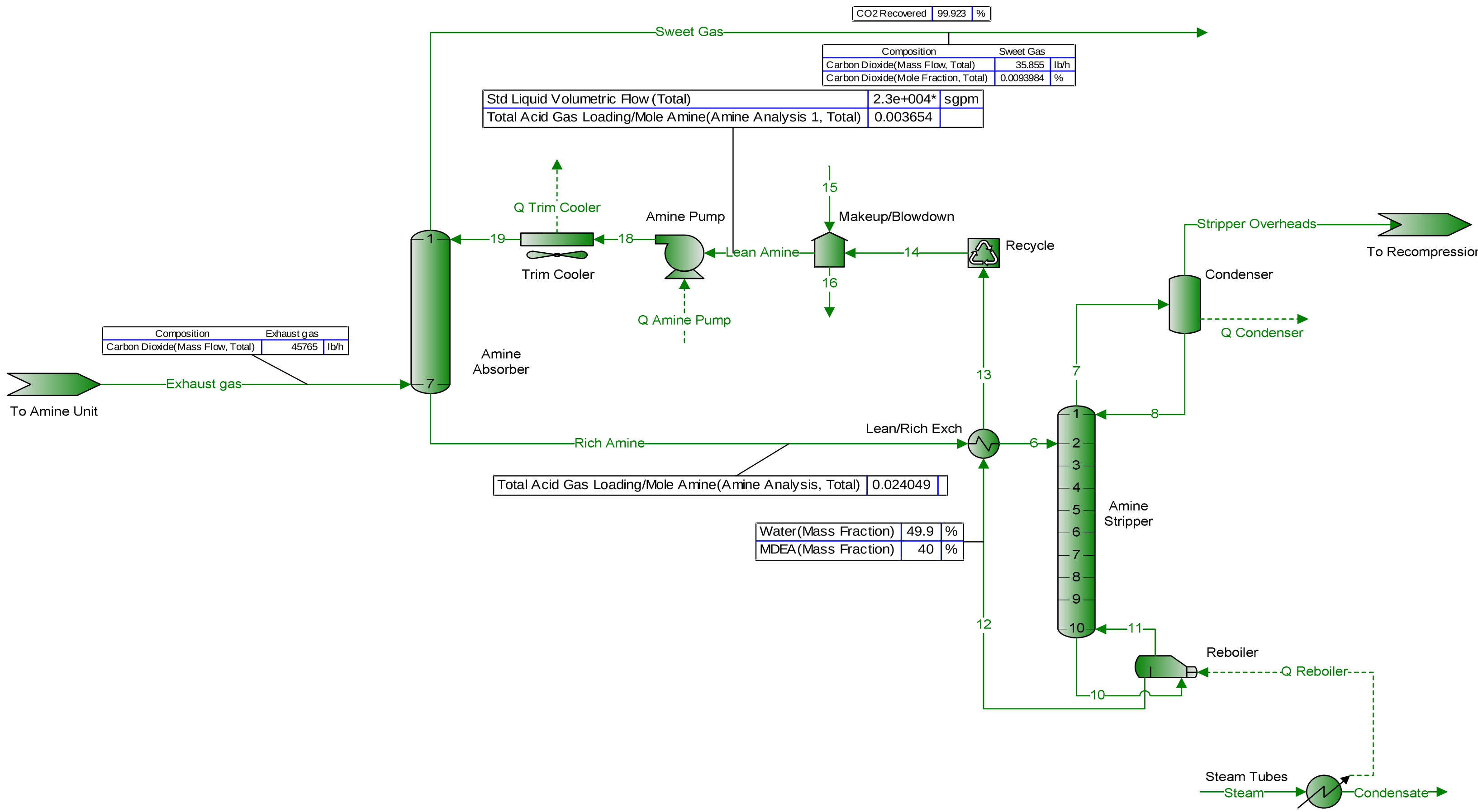
POTENTIAL TO EMIT FOR ENGINES REQUIRED FOR CCS

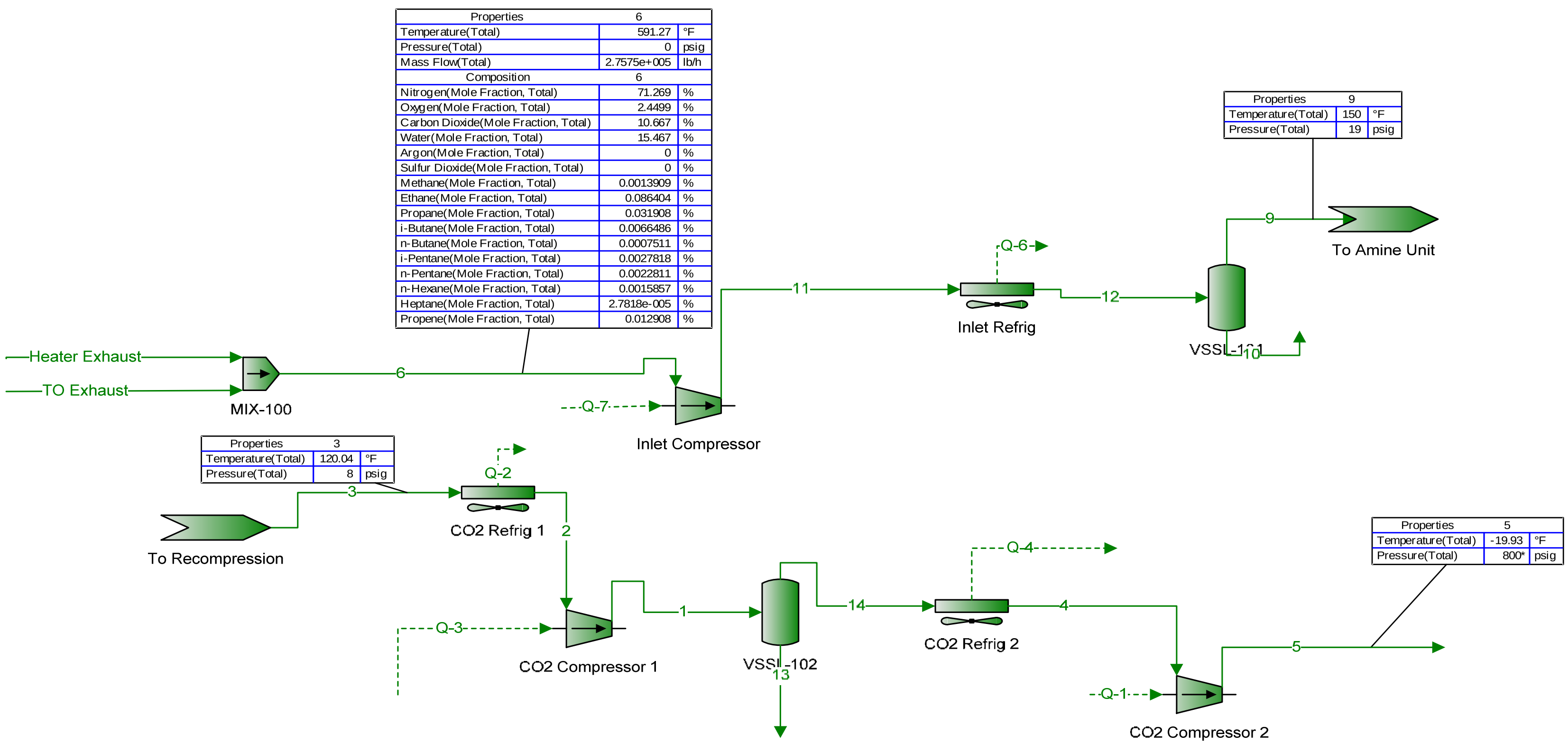
FRAC III PROJECT GHG PSD AIR PERMIT APPLICATION

MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

Description	Horsepower Needed (hp)	Fuel Consumption (Btu/hp-hr)	Annual Operating Hours (hr/yr)	Pollutant	Emission Factors [a]	Units	Total Potential to Emit (PTE) Hourly (lb/hr)	Total Potential to Emit (PTE) Annual (T/yr)
Inlet/Residue Compressors	13,001	7,400	8,760	CO	0.16	g/hp-hr	4.57	20.04
				NO_X	0.07	g/hp-hr	2.01	8.79
				PM	0.0099871	lb/MMBtu	0.96	4.21
				SO_2	4	ppmv	0.07	0.31
				VOC	0.26	g/hp-hr	7.44	32.57
				CH_2O	0.03	g/hp-hr	0.84	3.69
				CO_2	53.02	kg/MMBtu	11,245.48	49,255.20
Propane Compressor	2,510	7,400	4,380	CO	0.16	g/hp-hr	0.88	1.93
				NO_X	0.07	g/hp-hr	0.39	0.85
				PM	0.0099871	lb/MMBtu	0.19	0.41
				SO_2	4	ppmv	0.01	0.03
				VOC	0.26	g/hp-hr	1.44	3.14
				CH_2O	0.03	g/hp-hr	0.16	0.36
				Benzene	0.00044	lb/MMBtu	0.01	0.02
				CO_2	53.02	kg/MMBtu	2,170.69	4,753.81
TOTAL EMISSIONS						**CO**	**5.46**	**21.97**
						NO_X	**2.39**	**9.64**
						PM	**1.15**	**4.61**
						SO_2	**0.08**	**0.34**
						VOC	**8.87**	**35.71**
						CH_2O	**1.01**	**4.05**
						CO_2	**13,416.17**	**54,009.02**


CO2 Recovered | 99.923 | %
Sweet Gas
Composition | Sweet Gas
Carbon Dioxide(Mass Flow, Total) | 35.855 | lb/h
Carbon Dioxide(Mole Fraction, Total) | 0.0093984 | %
Std Liquid Volumetric Flow (Total) | 2.3e+004* | sgpm
Total Acid Gas Loading/Mole Amine(Amine Analysis 1, Total) | 0.003654
Q Trim Cooler
Amine Pump
15
Makeup/Blowdown
19
18
Lean Amine
14
Recycle
Trim Cooler
16
Stripper Overheads
To Recompression
Condenser
Q Amine Pump
Q Condenser
Composition | Exhaust gas
Carbon Dioxide(Mass Flow, Total) | 45765 | lb/h
Amine
Absorber
Exhaust gas
To Amine Unit
13
7
8
Lean/Rich Exch
Rich Amine
6
Total Acid Gas Loading/Mole Amine(Amine Analysis, Total) | 0.024049
Amine
Stripper
Water(Mass Fraction) | 49.9 | %
MDEA(Mass Fraction) | 40 | %
12
11
Reboiler
Q Reboiler
10
Steam Tubes
Steam
Condensate



Properties	6	
Temperature(Total)	591.27	°F
Pressure(Total)	0	psig
Mass Flow(Total)	2.7575e+005	lb/h
Composition	6	
Nitrogen(Mole Fraction, Total)	71.269	%
Oxygen(Mole Fraction, Total)	2.4499	%
Carbon Dioxide(Mole Fraction, Total)	10.667	%
Water(Mole Fraction, Total)	15.467	%
Argon(Mole Fraction, Total)	0	%
Sulfur Dioxide(Mole Fraction, Total)	0	%
Methane(Mole Fraction, Total)	0.0013909	%
Ethane(Mole Fraction, Total)	0.086404	%
Propane(Mole Fraction, Total)	0.031908	%
i-Butane(Mole Fraction, Total)	0.0066486	%
n-Butane(Mole Fraction, Total)	0.0007511	%
i-Pentane(Mole Fraction, Total)	0.0027818	%
n-Pentane(Mole Fraction, Total)	0.0022811	%
n-Hexane(Mole Fraction, Total)	0.0015857	%
Heptane(Mole Fraction, Total)	2.7818e-005	%
Propene(Mole Fraction, Total)	0.012908	%

Properties	9	
Temperature(Total)	150	°F
Pressure(Total)	19	psig

Properties	3	
Temperature(Total)	120.04	°F
Pressure(Total)	8	psig

Properties	5	
Temperature(Total)	-19.93	°F
Pressure(Total)	800*	psig

Compressor/Expander Report
Inlet Compressor

Client Name:	Lone Star NGL	**Job:**	CCS Model
Location:	Mont Belvieu	**Modified:**	5/30/2013 14:28
Flowsheet:	Inlet	**Status:**	Solved 3:29 PM, 5/30/2013

Stream Connections

Stream	Connection Type	Other Block	Stream	Connection Type	Other Block
6	Inlet	MIX-100	11	Outlet	Inlet Refrig
Q-7	Energy				

Block : Scalar Data

Polytropic Efficiency	70*	%	Isentropic K	1.32649	
Polytropic Head	57596.7	ft	Pressure Change	20	psi
Polytropic N	1.54229		Compression Ratio	2.36092	
Adiabatic Efficiency	66.8839	%	Compressor Rotation Speed		rpm
Adiabatic Head	55032.8	ft	Power	11459.0	hp

Notes:

Compressor/Expander Report
CO2 Compressor 1

Client Name:	Lone Star NGL	**Job:**	CCS Model
Location:	Mont Belvieu	**Modified:**	11/15/2012 16:04
Flowsheet:	Inlet	**Status:**	Solved 2:37 PM, 5/30/2013

Stream Connections

Stream	Connection Type	Other Block	Stream	Connection Type	Other Block
2	Inlet	CO2 Refrig 1	1	Outlet	VSSL-102
Q-3	Energy				

Block : Scalar Data

Polytropic Efficiency	70*	%	Isentropic K	1.16681	
Polytropic Head	43134.0	ft	Pressure Change	193	psi
Polytropic N	1.25665		Compression Ratio	9.89567	
Adiabatic Efficiency	67.0246	%	Compressor Rotation Speed		rpm
Adiabatic Head	41300.5	ft	Power	1477.14	hp

Notes:

Compressor/Expander Report
CO2 Compressor 2

Client Name:	Lone Star NGL	**Job:**	CCS Model
Location:	Mont Belvieu	**Modified:**	11/15/2012 16:46
Flowsheet:	Inlet	**Status:**	Solved 3:45 PM, 5/30/2013

Stream Connections

Stream	Connection Type	Other Block	Stream	Connection Type	Other Block
4	Inlet	CO2 Refrig 2	5	Outlet	
Q-1	Energy				

Block : Scalar Data

Polytropic Efficiency	70*	%	Isentropic K	2.16006	
Polytropic Head	1462.11	ft	Pressure Change	601	psi
Polytropic N	4.29580		Compression Ratio	3.81241	
Adiabatic Efficiency	45.1116	%	Compressor Rotation Speed		rpm
Adiabatic Head	942.261	ft	Power	64.5840	hp

Notes:

APPENDIX E
GENERAL SUPPORTING DOCUMENTATION

FRAC III PROJECT GHG PSD AIR PERMIT APPLICATION

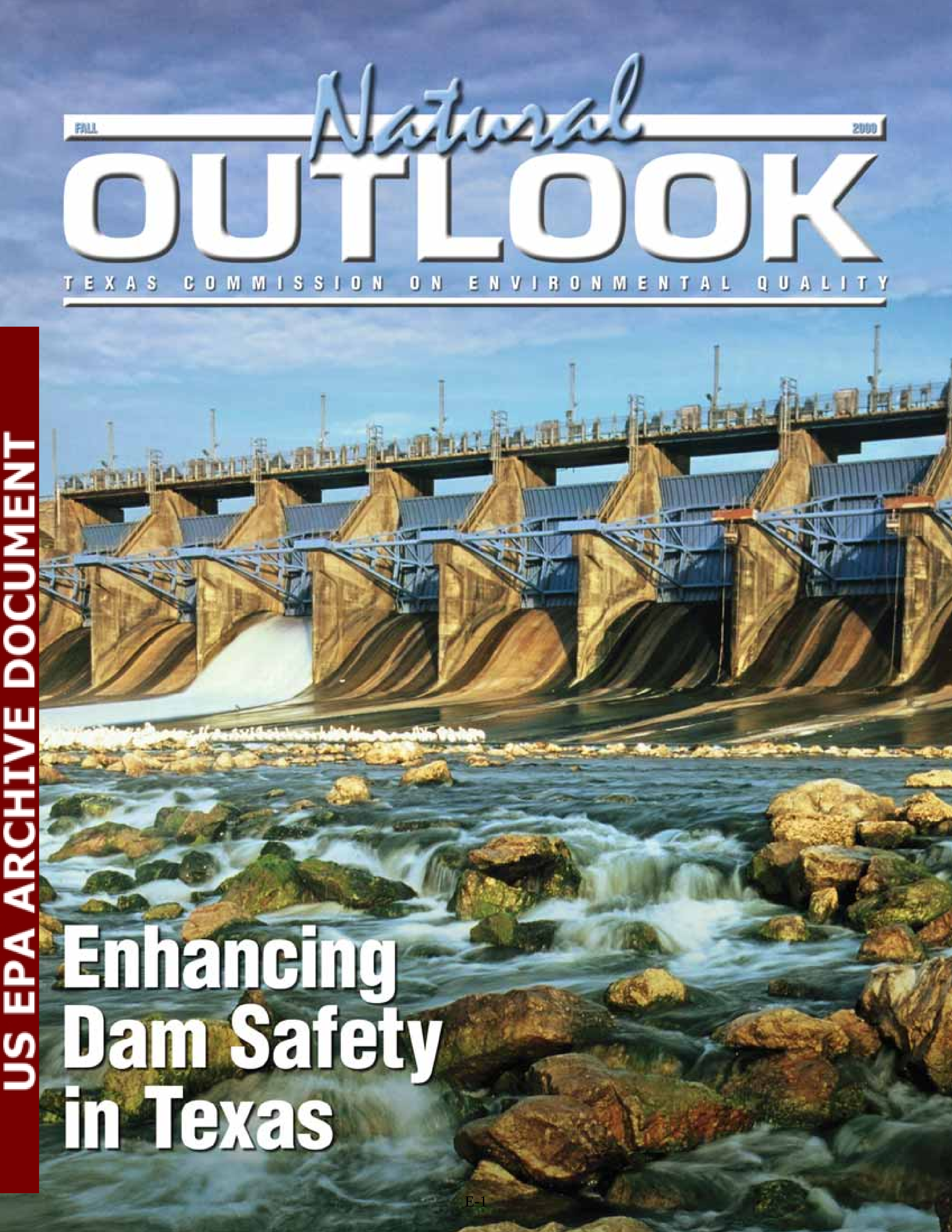
MONT BELVIEU GAS PLANT

LONE STAR NGL FRACTIONATORS LLC

FALL 2000

Natural OUTLOOK

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY



Enhancing Dam Safety in Texas

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Natural OUTLOOK

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Exploring environmental issues and challenges in Texas

COVER: Lake Livingston Dam

Photo courtesy of Trinity River Authority

Using Water Wisely

Drought contingency planning helps keep the water flowing for Texans

Any Texan who has experienced a sizzling hot day during a seemingly never-ending Texas "dry spell" definitely knows the worth of water. But not every Texan who turns on a tap is aware of the careful planning required to keep that water flowing, even during a drought.

Planning for Drought

During a drought, there is less rainfall and less water available for human use. Water utilities throughout Texas must plan ahead to reduce the impact of droughts, reduce peak demand, and extend their water supplies.

Drought contingency planning in Texas grew out of legislation passed in 1997 after a severe 1996 drought, when 86 percent of Texas counties qualified for emergency aid. The Texas Legislature directed the TCEQ to adopt rules establishing common drought plan requirements for water suppliers.

As a result, around 736 irrigation districts, wholesale public water suppliers, and retail public water suppliers that serve 3,300 connections or more are required to submit drought contingency plans to the TCEQ every five years. Retail public water suppliers that serve fewer than 3,300 connections must prepare and adopt a drought contingency plan and have it available to show to the TCEQ upon request.

Implementing Drought Triggers

Drought contingency plans vary by supplier; however, a common feature is a structure that imposes increasingly stringent drought response measures in successive stages as water supply conditions worsen. Most suppliers define three to five drought response stages that include "triggering" criteria for each stage.

Once triggered, Stage I of a contingency plan might start, for example, with a voluntary watering schedule. If the desired reduction in water use is not achieved, mandatory restrictions on some outdoor water uses might be the next stage of the plan. If these efforts fail to sufficiently reduce usage, a ban on all outdoor use of water might be implemented in the final stage.

Conserving Water

Many water suppliers also have water conservation plans. A water conservation plan differs from a drought contingency plan in that it centers around the everyday responsible stewardship of water, whereas contingency measures are implemented only as a matter of necessity, when a supplier needs to manage a water-supply or -demand issue. Conservation can extend water supplies and potentially prevent the necessity of implementing a drought contingency plan.

Making Every Drop Count

Each and every Texan can help keep the water flowing by supporting their supplier's contingency efforts during a drought and by making water conservation a part of their everyday activities.

For water conservation tips, visit the Texas Water Development Board's "Save Water" Web page, at www.twdb.state.tx.us/data/drought/save_water2.asp. ★

Partnership Protects "America's Sea"

The Gulf of Mexico Alliance releases plan for healthy and resilient coasts

The Gulf of Mexico is the ninth largest body of water in the world, with a total area of nearly 600,000 square miles. Sometimes called "America's Sea," it is bounded by Florida, Alabama, Mississippi, Louisiana, and Texas on the north; Mexico on the west and south; and the island of Cuba on the southeast.

The gulf sustains an abundance of marine life, 28 different species of whales and dolphins, and complex coral reef communities. Its coastal areas, which contain half the wetlands in the United States, are home to vital natural resources, nesting waterfowl habitat, colonial waterbird rookeries, and many endangered species, such as the Kemp's Ridley sea turtle.

Beautiful beaches and rich recreational fishing grounds support a booming tourism industry. And with one of the most developed oil and gas industries in the world, as well as several ports that lead the nation in total commerce, it is easy to see why the Gulf of Mexico is critical to the U.S. economy.

The health of the gulf, however, faces many serious challenges. Key coastal habitat is threatened by increased coastal development, sea level rise, shoreline erosion, and land subsidence. The Mississippi River and its tributaries transport nutrient runoff from agricultural activity in 31 upstream states to the gulf, stimulating an overgrowth of algae. This algae sinks and decomposes, helping to make the gulf the world's second largest "zone of hypoxia," or area of water with little to no oxygen. This annually recurring "dead zone" results in the loss of fish, shellfish, and plants.

Gulf States Join Forces

In 2004, recognizing that the economies and quality of life of the citizens in their states were linked to the ecological health of the Gulf of Mexico, the governors of Alabama, Florida, Louisiana, Mississippi, and Texas joined forces to form the Gulf of Mexico Alliance. This partnership, supported by thirteen federal agencies, was the

Photo courtesy of Kevin Stillman/TxDOT

beginning of a regional collaborative effort to improve the health of the Gulf of Mexico.

The governor of each state appointed one or more representatives to provide the vision for and make strategic decisions about alliance activities. TCEQ Commissioner Buddy Garcia was designated to represent Texas on the Alliance Management Team.

“The economic vitality of the Gulf Coast depends on the ecological health of the Gulf of Mexico,” says Garcia. “Many of the challenges we face in the gulf region cross state lines. Through the Gulf of Mexico Alliance, the five gulf states are able to combine expertise and resources to resolve shared issues.”

Taking Action for Coastal Health

The first project undertaken by the alliance was to develop the Governors’ Action Plan for Healthy and Resilient Coasts. Released in 2006, this three-year plan identified specific actions needed to improve the health of coastal areas. The results exceeded initial expectations and included the following accomplishments:

- Coastal Ecosystem Learning Centers were established in each of the five gulf states and Veracruz, Mexico.
- A Regional Sediment Management Master Plan was drafted. This plan provides a framework for better management of gulf sediment resources, facilitating a reduction in coastal erosion and storm damages, as well as the restoration of coastal habitats.
- Binational workshops designed to standardize the identification of harmful algal blooms and methods of field sampling were conducted in Texas, Florida, and Mexico.
- An ecosystem data portal was established. The portal will be used by resource managers to evaluate habitat extent and changes over time.
- A regional Nutrient Criteria Research Framework was developed. This has led to a better understanding of nutrient impacts to gulf ecosystems, as well as a coordinated approach to managing them.

Photo courtesy of Chase Fountain/Texas Parks and Wildlife Department

Photo courtesy of Texas Parks and Wildlife Department

Facts about the Gulf of Mexico

The Gulf of Mexico is one of the world's most ecologically and economically productive bodies of water, according to TCEQ Commissioner Buddy Garcia, who was appointed by Gov. Rick Perry to serve as Texas representative on the Gulf of Mexico Alliance Management Team. "Yet many people don't realize just how vital the gulf is to our nation and to the economy," says Garcia.

Here are a few facts about the Gulf of Mexico:

- **The gulf yields 69 percent of the shrimp and 70 percent of the oysters caught in the U.S.**
- **In 2008, recreational anglers caught 190 million fish in the Gulf of Mexico and surrounding waters, for a total weight of 73.6 million pounds.**
- **Four of the nation's top seven fishing ports are located on the Gulf Coast.**
- **The gulf yields more finfish, shrimp, and shellfish annually than the south- and mid-Atlantic, Chesapeake, and New England areas combined.**
- **Seven of the nation's top ten ports in terms of tonnage or cargo value are located on the Gulf Coast.**
- **According to the Minerals Management Service, offshore operations in the gulf produce a quarter of the domestic natural gas in the U.S. and one-eighth of its oil.**
- **More than a third (38%) of the U.S. shipbuilding industry is located along the Gulf Coast.**
- **With a watershed stretching from the Rockies to the Appalachians, the gulf provides much of the atmospheric moisture for North America.**
- **The gulf provides critical habitats for 75 percent of the migratory waterfowl that traverse the United States.**

Photo courtesy of Chase Fountain/Texas Parks and Wildlife Department

The Alliance Releases New Action Plan

Building on the successes of the first action plan, in 2008 the gulf states and their partners started working to develop a second plan. Released in June of 2009, the Governors' Action Plan II is a farther-reaching, five-year regional plan that, according to the alliance, "sets a course for actions designed to improve the health of coastal ecosystems and economies of the gulf in ways that a single entity could not achieve."

As in the first plan, Action Plan II identifies six regionally significant issues that can be effectively addressed through increased collaboration at the local, state, and federal levels:

- Water quality for healthy beaches and seafood
- Habitat conservation and restoration
- Ecosystems integration and assessment
- Reducing the impacts of nutrients on coastal ecosystems
- Coastal community resilience
- Environmental education

Each of these six issues is supported by a Priority Issue Team (PIT), a stakeholder group composed of scientific and technical experts from various governmental agencies, academia, nonprofit organizations, and private businesses in the five gulf states.

"The meat of the work for the priority issues happens at the PIT level," says Becky Walker, who handles coastal policy matters for Garcia and also serves as the alternate Texas representative on the Alliance Management Team. "The members of each team work together on a regular basis to identify specific actions that they are going to address and implement."

"The Gulf of Mexico Alliance gives us a chance to focus on our commonalities and what we can do together to impact the region," she says.

Action Plan II Addresses Challenges

Actions identified in Action Plan II collectively address four major challenges: sustaining the gulf economy, improving the health of the gulf ecosystem, mitigating the impacts of and adapting to climate changes, and mitigating any harmful effects on coastal water quality.

"The alliance is committed to a healthy Gulf of Mexico region," says Garcia, "and Action Plan II provides the blueprint for success."

To learn more about the Gulf of Mexico Alliance or to read Action Plan II in its entirety, visit **www.gulfofmexicoalliance.org**. To find out about important issues facing the Gulf Coast, visit the alliance's Environmental Education Network Web site, at **www.gulfallianceeducation.org**.

Photo courtesy of Michael A. Murphy/TxDOT

New Laws Address Agency Priorities

Legislation lays groundwork for cleaner environment

The 81st Texas Legislature concluded its regular session in June after passing 235 bills that affect TCEQ programs and address agency priorities. Following are some of the laws passed during the session.

Air

House Bill 1796

HB 1796 includes legislation pertaining to offshore geologic storage of carbon dioxide, the Texas Emissions Reduction Plan, a New Technology Implementation Grant Program, and greenhouse gas reporting requirements.

- **Offshore Geologic Storage of Carbon Dioxide**
  HB 1796, which lays the groundwork for Texas to develop an offshore carbon dioxide storage repository in state-owned submerged land, affects several agencies, including the TCEQ, the General Land Office, the University of Texas Bureau of Economic Geology, and the School Land Board.
  As an important part of the overall effort, the TCEQ will develop and adopt standards for monitoring, measuring, and verifying the permanent storage status of an offshore repository, ensuring that any standards adopted by the agency comply with EPA regulations.

- **The Texas Emissions Reduction Plan**
  HB 1796 extends the Texas Emissions Reduction Plan (TERP) until 2019. TERP is a comprehensive set of incentive programs aimed at reducing emissions in areas of the state identified as in nonattainment or near-nonattainment of federal ozone standards. The legislation allocated TERP funds as follows:

Emissions Reduction Incentive Grants (ERIG) Program, which includes the Clean School Bus Program, the Texas Clean Fleet Program, and the New Technology Implementation Grant Program	87.5%
New Technology Research and Development (NTRD)	9.0%
TERP administration	2.0%
Energy Systems Lab at Texas Engineering Experiment Station (TEES)	1.5%

- **New Technology Implementation Grant Program**
  HB 1796 also establishes the New Technology Implementation Grant (NTIG) program for the implementation of new technologies that reduce emissions from facilities and other stationary sources. Projects that could be eligible for the NTIG program include advanced clean energy projects, new technology projects that reduce emissions of regulated pollutants from point sources involving capital expenditures in excess of $500 million, and electricity storage projects related to renewable energy.

- **Greenhouse Gas Reporting Requirements**
  The TCEQ will work with the Texas Railroad Commission and the Texas Public Utilities Commission to review the development of federal greenhouse gas reporting requirements. The TCEQ will also establish an inventory of voluntary actions taken by state agencies and by businesses in the state since Sept. 1, 2001, to reduce carbon dioxide emissions. The TCEQ will work with the EPA to receive credit for early action under any federal rules that may be adopted for the regulation of greenhouse gases.

Senate Bill 1759

Texas Clean Fleet Program

SB 1759 creates a program that provides grants to fleet owners who replace qualifying diesel-powered vehicles with alternative-fuel or hybrid vehicles. The Texas Clean Fleet Program will be funded through TERP Emissions Reduction Incentives Grant (ERIG) funds.

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Agency Appropriations

The TCEQ will receive $1.01 billion for the 2010–2011 biennium, which began Sept. 1, 2009. Of this, $964.2 million is appropriated under the Appropriations Act (SB 1) and $43.6 million is appropriated through a supplemental appropriations bill to fund the Texas Emissions Reduction Plan (TERP), the state Superfund program, and response to natural disasters.

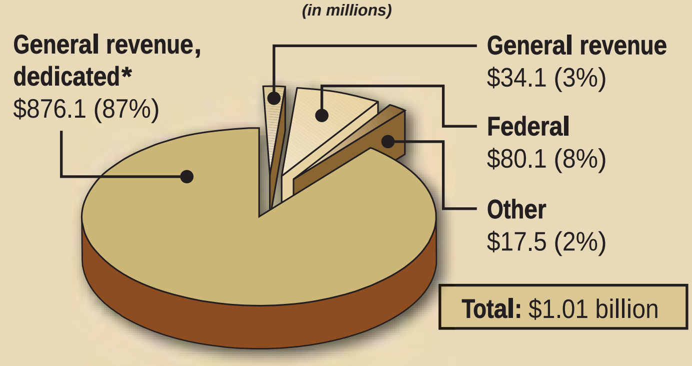
Included in the $964.2 million appropriation is $33.2 million for exceptional items such as the implementation of the new federal ozone standard, enhancements to the agency's Dam Safety Program, increased cleanup activities in the state Superfund program, an increase in grant funds for air quality planning, and information resource needs.

The Legislature also authorized an additional 66 full-time equivalent (FTE) positions for exceptional items and contingency riders, which include:

- 24 additional FTEs for enhancements to the Dam Safety Program
- 30 additional FTEs for implementation of the new ozone standard
- 2 additional FTEs to inspect a new low-level radioactive site in Andrews County
- 10 additional FTEs for contingency riders

TCEQ Financing for FY 2010–2011

(in millions)



*Fees assessed by the TCEQ and deposited to TCEQ accounts

Appropriations for the 2010–2011 biennium include the following program changes:

TCEQ Program	Increase or Decrease from 2008–2009 Biennium	Total for 2010–2011 Biennium
State Superfund Program	+ $8 million	$64.0 million
Air Quality Planning Grants	+ $2 million	$7.1 million
Petroleum Storage Tank Program	– $20 million	$52.3 million
Texas Emissions Reduction Plan	– $68 million	$233.0 million
Dam Safety Program (new funding)	N/A	$2.5 million

Enhancing Dam

Dam safety program expands

By Liz Carmack, contributing writer

Dams are a vital part of the national infrastructure and provide an infinite number of benefits to society. Dams provide drinking water, flood protection, renewable hydroelectric power, navigation, irrigation, and recreation. However, dams can also represent a public safety issue. A dam failure can result in loss of life, economic disaster, and extensive environmental damage.

The TCEQ Dam Safety Program is tasked with mitigating the risk of dam failures in Texas. With an infusion of $2.5 million in funding over the 2010–2011 biennium from the 81st Texas Legislature, and with plans to increase the number of inspectors in fiscal year 2011, the program is expanding.

Emphasis on Inspections

The program expansion was needed. Texas has the largest number of state-regulated dams in the country—7,139. (An additional 86 dams are federally operated and not under the TCEQ's purview.)

State-regulated dams are generally earthen and can range from 6 feet to 200 feet in height. Roughly 60 percent are privately owned. Another 24 percent are owned by soil and water conservation districts. The rest are the property of state and local governments, water districts, river authorities, and public utilities.

Dam Safety Program staff are responsible for ensuring that these structures, scattered across the state, are properly constructed and maintained. Their many duties include reviewing and approving plans and specifications for new dams or dam modifications, performing hydrologic and hydraulic analyses of dams, and inspecting existing dams and dams that are under construction.

"Our primary emphasis now is on dam inspection," says Warren Samuelson, manager of the TCEQ's Dam Safety Program. "Our goal is to inspect all dams that have a high-hazard or a significant-hazard rating within a five-year period ending August 2011."

Dams classified as high hazard or significant hazard have the potential to harm life or property and the environment should they fail. In Texas, 1,729 dams fall into these two classifications—963 are high-hazard dams and 766 are significant-hazard dams. According to the Texas Section of the American Society of Civil Engineers, 75 percent of the high-hazard dams were built before 1975. The age of this critical infrastructure heightens the importance of the agency's stepped-up inspection program.

The Dam Safety Program is two-thirds of the way toward meeting

Upper Brushy Creek WCID's Dam No. 6 in Cedar Park.

Safety in Texas

its inspection goal. Staff and TCEQ contractors inspected 292 high- and significant-hazard dams in 2007, 316 in 2008, and 550 as of June of this year.

The most frequent problems inspectors find include excessive vegetative growth, damage caused by animals burrowing into the dam, blockage of the spillway with trees or debris, erosion and undercutting of concrete structures, erosion of the spillway, damage to spillway pipes, and water seepage below the dam.

“Sometimes we’ll see cracking on the dam, especially with the weather as dry as it is, and sometimes we’ll see earthen slides,” Samuelson says. “Sometimes there is such excessive vegetative growth we can’t even inspect the dam. In that case, we require them to remove the vegetation.”

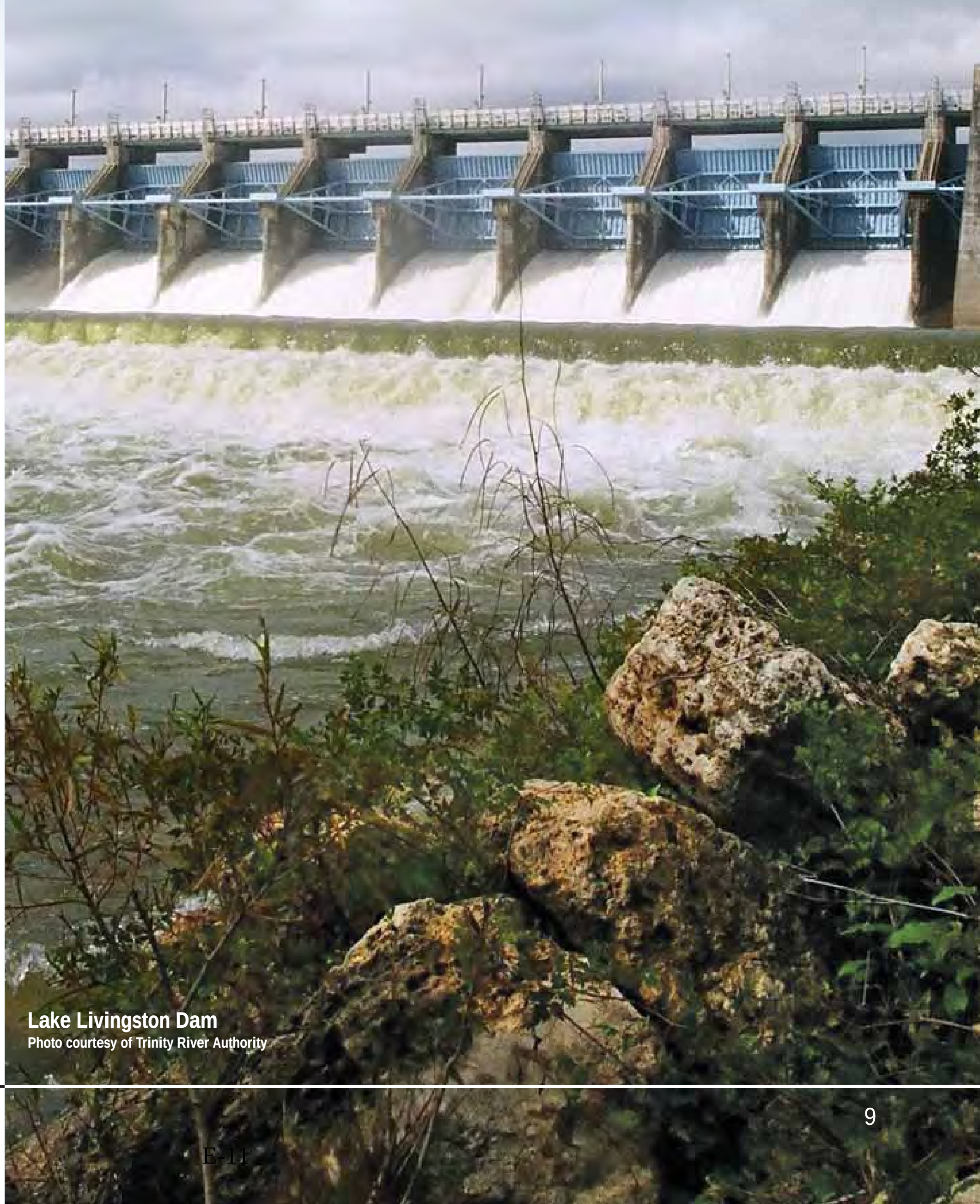
Following an inspection, the TCEQ provides a report to the dam’s owner. If any problems are found, the agency outlines them and the required actions needed to improve safety. Within 45 days, the owner is required to produce a plan and schedule for addressing the agency’s findings.

The agency depends on the owner to set the deadline for dam repairs. Cost and the owner’s available funds are often key factors in how quickly repairs are scheduled.

There is no state funding to help dam owners make required repairs of their dams. “It’s difficult sometimes for owners to get problems corrected because of lack of funds,” Samuelson says.

After accomplishing its goal in August 2011, the program will use a risk-based method—considering each dam’s classification, condition, and age—to schedule routine dam inspections.

As dams continue to age and areas develop, there is a constant need to re-evaluate some dam classifications to ensure they are still appropriate. Dam



Lake Livingston Dam
Photo courtesy of Trinity River Authority

Safety personnel use aerial photography, GIS maps from the Texas Natural Resources Information System, and Google Maps to check downstream land use. Increased development since a dam's previous classification could warrant a bump-up to a higher hazard rating.


TCEQ photo by Annette Berksan

The hiking trail at the top of the Upper Brushy Creek WCID's Dam No. 7 at Brushy Creek Lake Park in Cedar Park is popular with outdoor enthusiasts.

New Rules Support Enforcement

New state rules that went into effect at the beginning of 2009 (30 TAC, Chapter 299: "Dams and Reservoirs") improved the effectiveness of the Dam Safety Program. The rules provide the agency with more enforcement options through the courts.

"We can get an emergency order or go through the Texas Attorney General's office or district court to have a dam owner take required actions to repair the dam," Samuelson says.

The rules also changed the definition of "dam" to match the federal definition, which is:

- any artificial barrier 25 feet or higher that has a maximum impounding capacity of 15 acre-feet, or
- any artificial barrier 6 feet or higher that has a maximum impounding capacity of 50 acre-feet.

This automatically took about 400 smaller dams off the regulatory books, allowing agency staff to focus on larger dams that could have a greater impact should they fail.

"Before, our rules said a dam was anything over six feet tall," says Samuelson. "That was regardless of capacity, and included farm ponds, stock tanks, and detention ponds in neighborhoods."

Dam Hazard Classifications

The classification system of the federal Interagency Committee on Dam Safety categorizes dams according to the amount and type of damage that could occur should the dam fail, not according to the condition of the dam.

- **High-hazard dam – loss of life is probable**
- **Significant-hazard dam – no probable loss of life, but a failure could result in economic loss, environmental damage, disruption of lifeline facilities, etc.**
- **Low-hazard dam – no probable loss of life and few economic or environmental losses other than those suffered by the dam owner**

Reclassification could occur at any time based on:

- **Inspection and downstream evaluation by the TCEQ or the dam owner's engineer**
- **Breach analysis**
- **Review of aerial photography or maps along with fieldwork**

Emergency Action Plans Required

In order to help prevent loss of life and property, the new state rules require owners of high- and significant-hazard dams to submit emergency action plans to the TCEQ by Jan. 1, 2011. These plans must include emergency response procedures, a list of responsible parties, a notification flow chart to clarify communications, and complete contact information for all responsible parties.

"I know there are a lot of folks working on them now," Samuelson says. "After submission to the agency, they'll need to review the plan annually to update phone numbers and they'll need to update the entire plan on a five-year frequency."

During Hurricane Rita, in 2005, the emergency action plan initiated by the Trinity River Authority for the Lake Livingston Dam called for a release of waters from the lake to help alleviate a serious problem with the stability of the dam. The lake, which is east of Huntsville in East Texas, is the second-largest reservoir in the state. During the hurricane, the dam was severely damaged by high winds and waves.

"The authority saw the damage and initiated the emergency action plan," says Samuelson. "They notified the correct emergency management folks downstream and took action to close roads. They made major releases from the lake to get the water level down."

Program Increases Educational Efforts

The new rules cover the day-to-day operation and maintenance of dams. Each state-regulated dam must have an operation and maintenance plan, regardless of its classification. The plan must include scheduled engineering and maintenance inspections and a list of regular maintenance activities. Although owners have no set deadline to complete these plans, they must produce them if requested by the TCEQ.

The Dam Safety Program has increased its educational efforts to explain these new rules, to promote proper dam maintenance, and to emphasize the responsibilities of dam owners. Samuelson says response from dam owners has been encouraging.

"We've been able to get a lot of good information to the owners and they keep telling us to come back."

Since 2007, Samuelson has presented to more than 800 people at more than a dozen workshops around the state. The Dam Safety Program also provides guidance documents and forms on its Web site, at **www.tceq.state.tx.us/goto/dams**.

Challenges Met with Increased Awareness

Awareness about the deterioration of America's aging infrastructure—including its roads, bridges, drinking water systems, and dams—has grown, in part because of the *Report Card for America's Infrastructure*, which is issued annually by the American Society of Civil Engineers. This year, the group assigned U.S. dams a grade of D.

The Dam Safety Program's increased inspections and concentrated educational efforts are making a difference. "We have become more visible and folks know more about the program," Samuelson says. "We have people calling in and reporting situations to us. Sometimes owners who have been to a workshop and have seen something request an inspection."

Dam owners around the state are also becoming more interested in maintaining their dams and in understanding the state regulations more than ever before, says Samuelson, who has worked in the Dam Safety Program for more than 30 of his 37 years with the agency.

"We're getting a lot of response back from owners. They are trying to fix their dams. They realize their liability and responsibilities," he says. "A lot of people are paying attention to what we're saying."

Burrowing Beaver Contributes to Dam Collapse

The northeast Texas community of Edgewood received rain for a few days leading up to Thursday, March 12, 2009. That morning, rain fell again on the already damp town, and by 12:45 p.m. an earthen dam on the 25-acre private lake south of town had failed. A beaver had tunneled into the 14-foot-high earthen dam, contributing to the dam's collapse.

Water rushed through the southern parts of Edgewood, rising in lawns. The Edgewood Volunteer Fire Department reacted quickly, closing flooded FM 859. School buses were re-routed. Later, as the floodwaters receded, people were relieved to discover that no one was hurt and there was no significant property damage. The community was fortunate despite the dam's failure.

"We were scheduled to do an inspection there the following week," says Warren Samuelson, manager of the TCEQ's Dam Safety Program. "The dam's owner had seen water flowing through the dam but didn't completely understand the nature of the problem."

Texas has experienced dam failures in the past 20 years, according to Samuelson. In 2008, one dam failed, one dam's spillway failed, and one dam was overtopped. As of June of this year, in addition to the dam failure in Edgewood, the spillways of four other dams had failed. No dams had been overtopped. (Reporting is voluntary, so the actual numbers could be higher.)

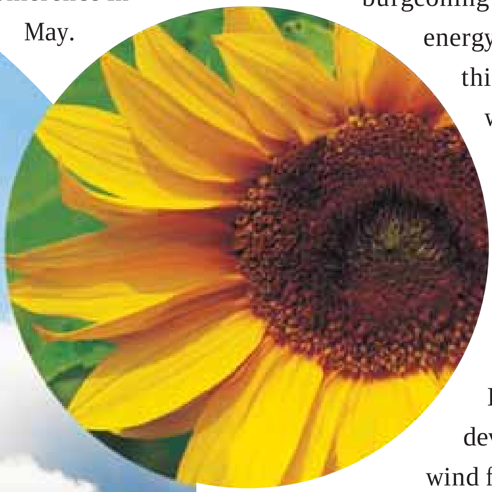
While most recent Texas dam failures have occurred in remote areas and have had relatively little impact downstream, failing dams located upstream of developed, populated areas could cause loss of life and millions of dollars in damage to property and the environment.

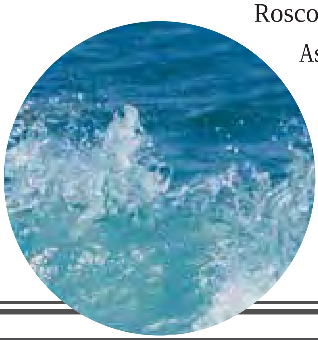
Environmental Excellence Takes Center Stage

Environmental awards recognize notable achievements

The Texas Environmental Excellence Awards program was created by the Texas Legislature in 1993 to recognize Texas citizens, communities, businesses, and organizations for their environmental efforts. The annual awards spotlight outstanding achievements in environmental preservation and protection in a variety of categories.

The winners of the 2009 Texas Environmental Excellence Awards were announced at the agency's Environmental Trade Fair and Conference in May.





Individual

Cliff Etheredge, Roscoe

In the small West Texas agricultural town of Roscoe, 45 miles west of Abilene, farmers have long considered the wind a nuisance because it dries out the land and kills the crops. Cliff Etheredge, however, had a vision of how to turn that nuisance into an asset.

Several years ago, Etheredge, a cotton farmer, noticed that wind turbines were springing up around Texas and wondered whether Roscoe could benefit from the burgeoning new industry of wind energy. After learning everything he could about wind energy, he was instrumental in convincing more than 350 landowners—representing nearly 100,000 acres—to get on board. He then found a developer to build a wind farm and formed the Roscoe Landowners Association to negotiate contracts and wind leases with the developer.

When completed later this year, the Roscoe Wind Farm will be the largest wind farm in the world, with 627 turbines and a total capacity of 781.5 megawatts—enough power to supply 265,000 homes.

Agriculture

Texas AgriLife Extension Service, College Station

Agricultural runoff containing nitrogen and phosphorus is one of several sources of pollution in the Arroyo Colorado, a 90-mile-long body of water that runs the length of the Rio Grande Valley. A soil testing program initiated by the Texas AgriLife Extension Service is helping to protect this important channel by reducing the amount of fertilizer that ends up in the Arroyo.

The Nutrient Management Education Program teaches growers in Cameron, Hidalgo, Starr, and Willacy counties how to collect samples for soil tests to determine how much fertilizer their soil really needs. The program also teaches proper fertilizer application and other conservation measures. To date, nitrogen fertilizer applications have been reduced by 3.3 million pounds and phosphorus fertilizer applications by 3.8 million pounds.

The growers who are putting these conservation principles into action are not only helping the environment, they are also benefiting financially, having reduced their fertilizer costs by anywhere from $9.47 an acre to more than $27 an acre.

Civic/Nonprofit

Build San Antonio Green, San Antonio

Build San Antonio Green is helping to move the practice of building green into the mainstream of San Antonio. The program certifies water- and energy-efficient homes through a quality review process. It also educates builders, remodelers, and homeowners about the benefits of green homes.

By May of this year, Build San Antonio Green had certified almost 247 new homes, representing an annual energy savings of 1.51 gigawatt-hours, which reduces nitrogen oxides by 2,492 pounds. This is the equivalent of taking 125 light-duty vehicles off the road for one year.

Build San Antonio Green was also honored on a national level this year when it received the Green Building Program of the Year award from the National Association of Home Builders.

Education

The Institute of Environmental and Human Health, Texas Tech University, Lubbock

The Institute of Environmental and Human Health (TIEHH) at Texas Tech University is ranked as one of the country's top environmental toxicology graduate programs. State-of-the-art laboratories are housed in six buildings covering more than 150,000 square feet. Researchers have partnered with almost 20 federal agencies and some of America's leading manufacturers.

An important study of Caddo Lake conducted by TIEHH aided in the cleanup of the Naval Weapons Industrial Reserve Plant, the transfer of Department of Defense property to the U.S. Fish and Wildlife Service, and the establishment of the Caddo Lake National Wildlife Refuge.

In April, TIEHH opened the Nonwovens and Advanced Materials Laboratory, where scientists are working to develop new textile materials, such as the recently patented Fibertect chemical decontamination wipe. Made from a unique nonwoven fabric, the product can absorb liquid and vapor toxicants and can be used on both people and equipment.

Government

Texas Department of Transportation

The Texas Department of Transportation has created a wide range of programs to address the state's environmental needs. Initiatives such as Bats 'N' Bridges and Don't Mess with Texas—as well as the agency's wildflower, wetlands preservation, alternative fuels, compost, and recycling programs—contribute to Texas communities with innovative approaches to conservation and beautification.

Roads are a major focus area for TxDOT. Over the past three years, the agency has reused more than 11 million tons of roadway materials. This saves landfill space and reduces emissions generated by producing and transporting new materials. To further cut emissions, the agency replaced fossil-fuel-powered engines with solar-powered ones on 250 roadway signs.

Underscoring its commitment to help drive Texas toward a cleaner future, TxDOT leads by example. More than 4,400 employees have signed up for the Clean Air Plan, the agency's internal air quality program, which includes a list of 22 actions employees can take to reduce ozone emissions. In addition, TxDOT's own fleet has more than 3,300 vehicles that use either compressed natural gas or propane.

Innovative Technology

Energy Transfer Technologies, Dallas

Moving natural gas across the state through pipelines requires significant amounts of energy, which has historically been provided by gas-fired engines. With the development of the ESelect Dual Drive, Energy Transfer Technologies is changing the way gas is delivered to market. The "dual drive" compression technology uses a combination of gas engines and electric motors to move the gas through the pipelines, drastically reducing both emissions and operating costs.

The ESelect Dual Drive allows compressors to switch between gas and electricity in response to changes in the demand for electricity. The compressors run mainly on electricity but switch to gas engines during peak demand times to help avoid the need to add generating capacity. Each 1,500 horsepower dual drive running on electricity can represent as much as a 95 percent reduction in exhaust emissions, along with reductions in noise, waste oil, and coolant usage.

Don't Miss Deadline for 2010 Awards

Deadline is October 16, 2009, for 2010 Environmental Excellence Awards

If you have been working to conserve, protect, or preserve the Texas environment, apply for the 2010 Texas Environmental Excellence Awards. The application deadline is Oct. 16, 2009.

Presented annually by the Governor of Texas and the TCEQ, the awards recognize outstanding and innovative environmental programs in 11 diverse categories:

- Agriculture
- Civic/Nonprofit
- Education
- Government
- Individual
- Innovative Technology
- Large Business, Nontechnical
- Large Business, Technical
- Small Business
- Water Conservation
- Youth

The Texas Environmental Excellence Awards are the highest distinction of environmental honor in the Lone Star State. They celebrate businesses, organizations, and individuals of all ages who are making a difference toward protecting Texas. The TCEQ will hold a banquet in Austin on May 5, 2010, to honor the award winners. Part of the Environmental Trade Fair and Conference, this celebration of environmental achievements is hosted by the TCEQ commissioners, with the special participation of Governor Rick Perry.

To download an application form or to apply online, go to www.teea.org.

Large Business, Nontechnical

Kimberly-Clark Corp., Paris

Kimberly-Clark, home to some of the world's most recognizable products for the home and personal care, takes a serious stance on environmental responsibility.

With sustainability as a core value, the K-C plant in Paris, Texas, has been working to improve the environment through energy conservation, waste reduction, and a sustainable use of natural resources. K-C recycles 99 percent of its manufacturing waste, which amounts to 23,000 tons per year. Recycled items include off-spec diapers, training pants, cardboard, metal (including soda cans), pallets, drums, trim, stretch wrap, and poly dust. For the last seven years, process water has been treated and used for landscape irrigation or has been recycled back into the process-water stream, conserving roughly 24 million gallons.

Large Business, Technical

Mars Snackfood US LLC, Waco

As a leading manufacturer of snack foods, Mars has billions of customers worldwide. Its Waco plant makes three of its major products: Snickers, Starburst, and Skittles.

Through an innovative production process, the company has found a way to lower fuel costs by using methane instead of natural gas. Two years ago, the Waco plant invested in new boiler

controls and instrumentation that would enable it to burn methane, which travels through a five-mile pipeline from the Waco Regional Landfill.

Landfill gas currently supplies nearly 50 percent of the plant's boiler fuel needs, saving the company $600,000 per year in energy costs.

Water Conservation

Boerne Independent School District, Boerne

Water is a cherished commodity to the Boerne Independent School District. An innovative rainwater harvesting system at the district's eco-friendly Champion High School is the first of its kind in the Texas public schools. Water captured from air-conditioning condensation, surface runoff, and roof runoff is stored in two elevated storage tanks and an underground stormwater pipe that is five feet in diameter and 800 feet in length.

This unique system, designed so that BISD can predict the amount of water it will need for athletic fields and landscape areas, can hold more than 224,000 gallons of water. The project has the potential of saving the school district an estimated $48,000 per year, with officials predicting that it will pay for itself in less than five years.

Champion High School also uses the collection system as part of its science curriculum, giving students valuable hands-on training in environmental stewardship.

Youth

Science Rocks U Wetlands Youth Brigade, Whiteface

In the small town of Whiteface, 45 miles west of Lubbock, an inventive group of teens is teaching the community valuable lessons about water conservation. Three years ago, as members of the Science Rocks U Wetlands Youth Brigade, the students began raising awareness about the Ogallala Aquifer and the unique wetlands that replenish it.

The Wetlands Youth Brigade calls their outreach project SPLASH, which stands for "Studying Playa Lakes and Saving Habitat." The students promote the importance of the aquifer through public seminars, school programs, festivals, brochures, and a music video.

The efforts of the group are starting to attract national attention. The students were invited to present at the U.S. Fish and Wildlife Service's first Youth Forum for the Environment. They are also currently organizing a National Wetlands Youth Brigade, and student groups from New Jersey and New Mexico have already joined.

Gregg A. Cooke Memorial Award

Richard E. Greene, Arlington

Richard E. Greene, former five-term Arlington mayor and Environmental Protection Agency Region 6 administrator, is the recipient of the 2009 Gregg A. Cooke Memorial Award for Exceptional Environmental Excellence.

As EPA regional administrator from 2003 until 2009, Greene was responsible for overseeing federal environmental programs in Arkansas, Louisiana, New Mexico, Oklahoma, and Texas. His time at the EPA was marked by tremendous challenges, which he met with strong leadership. His experience working with the different communities of the region was a valuable asset when leading the agency's response to hurricanes Katrina and Ike.

Greene is currently an adjunct professor at the School of Urban Affairs at the University of Texas at Arlington.

Gregg A. Cooke, who passed away in 2006, served as EPA Region 6 administrator from 1998 to 2003. The TCEQ created a permanent award in his name to honor his tireless efforts on behalf of the environment.

The Texas Environmental Excellence Awards program was created by the Texas Legislature in 1993 to recognize Texas citizens, communities, businesses, and organizations for their environmental efforts.

TCEQ Water Program Fees Increase

Fees secure funds for state water programs

A package of revised TCEQ rules, designed to ensure that sufficient funds are available to cover the cost of TCEQ water-program activities in the state for the 2010–2011 biennium, went into effect on July 30, 2009.

The fees affected by the rule package are the Consolidated Water Quality Fee, paid by holders of wastewater discharge permits; the Public Health Service Fee, paid by public water systems; and the Water Use Assessment Fee, paid by holders of water rights.

Why an Increase Was Necessary

General revenue appropriations to the TCEQ have declined from the $51 million received in the 2004–2005 biennium. For the 2010–2011 biennium, the 81st Legislature appropriated $9.4 million per year in general revenue to support the TCEQ's existing water programs, which is equivalent to what was appropriated for the previous biennium. This leaves the agency with an $18 million per year shortfall to fully fund its water-program activities at the appropriated amounts for the 2010–2011 biennium.

To address this shortfall, it was necessary to increase the revenues collected from water fees deposited to Water Resource Management Account 153. This account is the primary source of state funding for all of the agency's water programs. While revenue from existing fees deposited to Account 153 has remained stable, the demand for funding from the account has increased. As a result, the fund balance is almost depleted.

Account 153 supports a wide range of activities and programs, including those related to water rights, storm water, public drinking water, Total Maximum Daily Load development, water utilities, wastewater, river compacts, water-availability modeling, water assessment, concentrated animal feeding operations, sludge, the Clean Rivers Program, and groundwater protection.

The fee increases will allow the agency to maintain these activities at basically the current level.

Selection of Fees

The agency considered all of its water fees when determining how to best ensure that it could continue to carry out its water related programs beginning in fiscal year 2010.

The Consolidated Water Quality Fee, Public Health Service Fee, and Water Use Assessment Fee were selected because they are within the agency's direct authority to adjust without statutory changes; they generate a significant percentage of the revenue deposited to Account 153; their revenue stream is generally constant; and their payers constitute a broad segment of the state's population, including industry, large and small municipalities, public and private utilities, and the public, indirectly, through monthly utility bills.

The increase in the Water Use Assessment Fee will generate approximately

Payment Cycle

The payment cycle will not change under the new rule package, with payment of fees due thirty days from the billing date.

The bills will be mailed as follows:

Public Health Service Fee:	**Oct. 2009**
Consolidated Water Quality Fee:	**Nov. 2009**
Water Use Assessment Fee:	**Jan. 2010**

For more information, visit www.tceq.state.tx.us/goto/waterfees.

$554,000 of the amount the agency needs to address the shortfall for the 2010–2011 biennium. The increase in the Consolidated Water Quality Fee will generate an additional $3 million per year, and the increase in the Public Health Service Fee an additional $15 million per year. To generate that $15 million, the Public Health Service Fee will be assessed at $2.15 per connection per year. For the average Texan, this amounts to 18 cents per month per household.

Previous Fee Increases

The Consolidated Water Quality Fee has not been increased since it first became effective on Oct. 6, 2002.

The Public Health Service Fee was last amended in 2001 to the current flat fee or per-connection calculation. Systems paying a flat fee have not seen an increase since 2001. The formula for calculating the per-connection rate also has not changed since 2001. Fees for the public water systems that pay per connection have increased due only to system growth.

In 1992, the TCEQ began assessing a fee on holders of water rights. In 2001, this fee became known as the Water Use Assessment Fee. The last changes to the fee were implemented in 1994.

New Laws Address Agency Priorities *cont. from page 7*

Water

Senate Bill 1757

Medical Waste Disposal

To help ensure that unused pharmaceuticals do not enter a wastewater system, the TCEQ will conduct a study and submit recommendations to the Legislature regarding the methods currently used in Texas to safely handle and dispose of pharmaceuticals, medical sharps, and other potentially dangerous waste; alternative methods used for that purpose, including the methods used in other states; and the effects of the various methods on public health and the environment.

Fees

House Bill 1433

Texas Water Code Statutory Cap

The statutory cap set in the Texas Water Code for the water use assessment fee and the consolidated water quality fee has been raised from $75,000 to $100,000. The cap can be raised annually, up to a maximum of $150,000, to reflect the percentage change during the preceding year in the Consumer Price Index for All Urban Consumers.

Utilities, Districts, and Authorities

Senate Bill 361

Emergency Preparedness

In the aftermath of a natural disaster such as Hurricane Ike, the availability of drinking water and effective wastewater treatment is a concern.

SB 361 addresses that concern by requiring an affected utility to ensure the emergency operation of its water system during an extended power outage as soon as safe and practicable following the occurrence of a natural disaster. In addition, an affected utility must adopt and submit to the TCEQ for review and approval an emergency preparedness plan that demonstrates the utility's ability to provide emergency operations.

An affected utility is defined as a retail public utility, exempt utility, or provider or conveyor of potable or raw water service that furnishes water service to more than one customer in a county with a population of 3.3 million or more or in a county with a population of 400,000 or more adjacent to a county with a population of 3.3 million or more.

Agency Administration

House Bill 3544

Electronic Means of Information Transmission

The TCEQ is authorized to use electronic means of transmission for information issued or sent by the agency. The law also provides exemption from non-disclosure of e-mail addresses submitted for the purpose of providing public comment or receiving notices, orders, or decisions. If public information exists in electronic or magnetic medium, then a copy may be requested in either medium. If the information cannot be provided in the requested medium, the TCEQ will provide a copy in another medium that is acceptable to the requester.

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TCEQ Strike Team

Ready to communicate in a crisis

TCEQ photo by Cameron Lopez

By Diana Barkley,
TCEQ Agency Communications

When Hurricane Ike tore through Galveston and other Gulf Coast communities last year, the TCEQ Emergency Response Strike Team was ready for storm duty. This year, the team is again prepared to play a key role in coordinating and supporting communication systems during disasters and other emergencies.

In June, Strike Team members participated in a Department of Defense exercise at Camp Mabry in Austin. The exercise featured a mock hurricane five days before landfall. The goal: test radio interoperability and satellite communication systems among partners from local, state, and federal agencies, including the military—in the immediate local area, within Texas, and out of state.

The TCEQ team was able to connect and share radio and satellite communications with partners at three Texas sites—Austin, Midland, and the Rio Grande Valley—as well as 17 out-of-state sites. Testing the reach of the system, the team was also able to communicate with the International Space Station.

As a result of the exercise, the DoD certified the TCEQ's system, giving the agency access to the National Guard's satellite communications system.

"This provides us with a secure communications and support system with a high satellite bandwidth, which enables us to use video streaming, wireless video, and high-quality VoIP [Voice over Internet Protocol] to make phone calls through computer networks," says Kelly Crunk of the TCEQ Strike Team. "This also helps us support other agencies during an emergency situation."

§98.37 Records That Must be Retained.

In addition to the requirements of §98.3(g), you must retain the applicable records specified in §§98.34(f) and (g), 98.35(b), and 98.36(e).

§98.38 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table C-1 of Subpart C—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
Coal and Coke	**mmBtu/short ton**	**kg CO_2 /mmBtu**
Anthracite	25.09	103.54
Bituminous	24.93	93.40
Subbituminous	17.25	97.02
Lignite	14.21	96.36
Coke	24.80	102.04
Mixed (Commercial sector)	21.39	95.26
Mixed (Industrial coking)	26.28	93.65
Mixed (Industrial sector)	22.35	93.91
Mixed (Electric Power sector)	19.73	94.38
Natural Gas	**mmBtu/scf**	**kg CO_2 /mmBtu**
Pipeline (Weighted U.S. Average)	1.028×10^{-3}	53.02
Petroleum Products	**mmBtu/gallon**	**kg CO_2 /mmBtu**
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Still Gas	0.143	66.72
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73

Table C-1 of Subpart C—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel Type	**Default High Heat Value**	**Default CO_2 Emission Factor**
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.83
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.129	70.97
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.49
Heavy Gas Oils	0.148	74.92
Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.49
Fossil Fuel-derived Fuels (Solid)	**mmBtu/short ton**	**kg CO_2 /mmBtu**
Municipal Solid Waste[1]	9.95	90.7
Tires	26.87	85.97
Fossil Fuel-derived Fuels (Gaseous)	**mmBtu/scf**	**kg CO_2 /mmBtu**
Blast Furnace Gas	0.092×10^{-3}	274.32
Coke Oven Gas	0.599×10^{-3}	46.85
Biomass Fuels - Solid	**mmBtu/short Ton**	**kg CO_2 /mmBtu**
Wood and Wood Residuals	15.38	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	25.83	105.51
Biomass Fuels - Gaseous	**mmBtu/scf**	**kg CO_2 /mmBtu**
Biogas (Captured methane)	0.841×10^{-3}	52.07
Biomass Fuels - Liquid	**mmBtu/gallon**	**kg CO_2 /mmBtu**
Ethanol (100%)	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1]Allowed only for units that do not generate steam and use Tier 1.

Table C-2 of Subpart C—Default CH_4 and N_2O Emission Factors for Various Types of Fuel.

Fuel Type	**Default CH_4 Emission Factor (kg CH_4 /mmBtu)**	**Default N_2O Emission Factor (kg N_2O/mmBtu)**
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-2}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}

Fuel Type	Default CH_4 Emission Factor (kg CH_4 /mmBtu)	Default N_2O Emission Factor (kg N_2O/mmBtu)
Petroleum (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2 x 10-05	1.0×10^{-04}
Coke Oven Gas	4.8 x 10-04	1.0×10^{-04}
Biomass Fuels - Solid (All fuel types in Table C-1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels – Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/MMBtu.
[1]Allowed only for units that do not generate steam and use Tier 1.

Table C-2 of Subpart C—Default CH_4 and N_2O Emission Factors for Various Types of Fuel.

Fuel Type	Default CH_4 Emission Factor (kg CH_4 /mmBtu)	Default N_2O Emission Factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-2}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels - Solid (All fuel types in Table C-1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels – Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/MMBtu.

Subpart D—Electricity Generation

§98.40 Definition of the source category.

Facility/Compound Specific Fugitive Emission Factors

Equipment/ Service	Ethylene Oxide [1]	Phosgene [2]	Butadiene [3]	Petroleum Marketing Terminal [4]	Oil and Gas Production Operations [5]				Refinery [6]
					Gas	Heavy Oil <20° API	Light Oil >20°	Water/Light Oil	
Valves					0.00992	0.0000185	0.0055	0.000216	
Gas/Vapor	0.000444	0.00000216	0.001105	0.0000287					0.059
Light Liquid	0.00055	0.00000199	0.00314	0.0000948					0.024
Heavy Liquid				0.0000948					0.00051
Pumps	0.042651	0.0000201	0.05634		0.00529	0.00113 [10]	0.02866	0.000052	
Light Liquid				0.00119					0.251
Heavy Liquid				0.00119					0.046
Flanges/Connectors	0.000555	0.00000011	0.000307		0.00086	0.00000086	0.000243	0.000006	0.00055
Gas/Vapor				0.000092604					
Light Liquid				0.00001762					
Heavy Liquid				0.0000176					
Compressors	0.000767		0.000004		0.0194	0.0000683	0.0165	0.0309	1.399
Relief Valve	0.000165	0.0000162	0.02996		0.0194	0.0000683	0.0165	0.0309	0.35
Open-ended Lines [7]	0.001078	0.00000007	0.00012		0.00441	0.000309	0.00309	0.00055	0.0051
Sampling	0.000088		0.00012						0.033
Connectors					0.00044	0.0000165	0.000463	0.000243	
Other [9]					0.0194	0.0000683	0.0165	0.0309	
Gas/Vapor				0.000265					
Light/Heavy Liquid				0.000287					
Process Drains					0.0194	0.0000683	0.0165	0.0309	0.07

Table Notes: All factors are in units of (lb/hr)/component.

1. Monitoring must occur at a leak definition of 500 ppmv. No additional control credit can be applied to these factors. Emission factors are from EOIC Fugitive Emission Study, Summer 1988.

2. Monitoring must occur at a leak definition of 50 ppmv. No additional control credit can be applied to these factors. Emission factors are from Phosgene Panel Study, Summer 1988.

3. Monitoring must occur at a leak definition of 100 ppmv. No additional control credit can be applied to these factors. Emission factors are from Randall, J. L., et al., Radian Corporation. Fugitive Emissions from the 1,3-butadiene Production Industry: A Field Study. Final Report. Prepared for the 1,3-Butadiene Panel of the Chemical Manufacturers Association. April 1989.

4. Control credit is included in the factor; no additional control credit can be applied to these factors. Monthly AVO inspection required.

5. Factors give the total organic compound emission rate. Multiply by the weight percent of non-methane, non-ethane organics to get the VOC emission rate.

6. Factors are taken from EPA Document EPA-453/R-95-017, November 1995, Page 2-13.

7. The 28 Series quarterly LDAR programs require open-ended lines to equipped with a cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.

8. Emission factor for Sampling Connections is in terms of pounds per hour per sample taken.

9. For Petroleum Marketing Terminals"Other" includes any component excluding fittings, pumps, and valves. For Oil and Gas Production Operations, "Other" includes diaphragms, dump arms, hatches, instruments, meters, polished rods, and vents.

10. No Heavy Oil - Pump factor was derived during the API study. The factor is the SOCMI without C_2 Heavy Liquid - Pump factor with a 93% reduction credit for the physical inspection.

Uncontrolled SOCMI Fugitive Emission Factors

Equipment/Service	SOCMI Average[1]	SOCMI Without C_2[2]	SOCMI With C_2[2]	SOCMI Non-Leaker[3]
Valves				
Gas/Vapor	0.0132	0.0089	0.0258	0.00029
Light Liquid	0.0089	0.0035	0.0459	0.00036
Heavy Liquid	0.0005	0.0007	0.0005	0.0005
Pumps				
Light Liquid	0.0439	0.0386	0.144	0.0041
Heavy Liquid	0.019	0.0161	0.0046	0.0046
Flanges/Connectors				
Gas/Vapor	0.0039	0.0029	0.0053	0.00018
Light Liquid	0.0005	0.0005	0.0052	0.00018
Heavy Liquid	0.00007	0.00007	0.00007	0.00018
Compressors	0.5027	0.5027	0.5027	0.1971
Relief Valve (Gas/Vapor)	0.2293	0.2293	0.2293	0.0986
Open-ended Lines[4]	0.0038	0.004	0.0075	0.0033
Sampling Connections[5]	0.033	0.033	0.033	0.033

Notes: All factors are in units of (lb/hr)/component.

1. Factors are taken from EPA Document, EPA-453/R-95-017, November 1995, Page 2-12
2. Factors are TCEQ derived.
3. Control credit is included in the factor; no additional control credit can be applied to these factors. AVO walk-through inspection required.
4. The 28 series quarterly LDAR programs require open-ended lines to be equipped with an appropriate sized cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.
5. Use the SOCMI Sampling factor for Non-Leakier. Emission factor is in terms of (lbs/hr)/Sample Taken.

Control Efficiencies for TCEQ Leak Detection and Repair Programs

Equipment/Service	28M	28RCT	28VHP	28MID	28LAER	Audio/Visual/Olfactory[1]
Valves						
Gas/Vapor	75%	97%	97%	97%	97%	97%
Light Liquid	75%	97%	97%	97%	97%	97%
Heavy Liquid[2]	0%[3]	0%[4]	0%[4]	0%[4]	0%[4]	97%
Pumps						
Light Liquid	75%	75%	85%	93%	93%	93%
Heavy Liquid[2]	0%[3]	0%[3]	0%[5]	0%[6]	0%[6]	93%
Flanges/Connectors						
Gas/Vapor[7]	30%	30%	30%	30%	97%	97%
Light Liquid[7]	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[8]	75%	97%	97%	97%	97%	97%
Sampling Connections	75%	97%	97%	97%	97%	97%

1. Audio, visual, and olfactory walk-through inspections are applicable for inorganic/odorous and low vapor pressure compounds such as chlorine, ammonia, hydrogen sulfide, hydrogen fluoride, and hydrogen cyanide.
2. Monitoring components in heavy liquid service is not required by any of the 28 Series LDAR programs. If monitored with an instrument, the applicant must demonstrate that the VOC being monitored has sufficient vapor pressure to allow reduction.
3. No credit may be taken if the concentration at saturation is below the leak definition of the monitoring program (i.e. (0.044 psia/14.7 psia) x 106 = 2,993 ppmv versus leak definition = 10,000 ppmv).
4. Valves in heavy liquid service may be given a 97% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.
5. Pumps in heavy liquid service may be given an 85% reduction credit if monitored at 2,000 ppmv by permit condition provided that the concentration at saturation is greater than 2,000 ppmv.
6. Pumps in heavy liquid service may be given a 93% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.
7. If the applicant decides to monitor connectors using an organic vapor analyzer (OVA) at the same leak definition as valves, then the applicable valve reduction credit may be used instead of the 30% reduction credit. If this option is chosen, the applicant shall continue to perform the weekly physical inspections in addition to the quarterly OVA monitoring.
8. The 28 Series quarterly LDAR programs require open-ended lines to be equipped with an appropriately sized cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.

industry segment only if emission sources specified in paragraph § 98.232(c) emit 25,000 metric tons of CO_2 equivalent or more per year. Facilities must report emissions from the natural gas distribution industry segment only if emission sources specified in paragraph § 98.232(i) emit 25,000 metric tons of CO_2 equivalent or more per year.

(b) For applying the threshold defined in § 98.2(a)(2), natural gas processing facilities must also include owned or operated residue gas compression equipment.

§ 98.232 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraph (b) through (i) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraph (j) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section.

(b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions.

(c) For an onshore petroleum and natural gas production facility, report CO_2, CH_4, and N_2O emissions from only the following source types on a well pad or associated with a well pad:

(1) Natural gas pneumatic device venting.

(2) [Reserved]

(3) Natural gas driven pneumatic pump venting.

(4) Well venting for liquids unloading.

(5) Gas well venting during well completions without hydraulic fracturing.

(6) Gas well venting during well completions with hydraulic fracturing.

(7) Gas well venting during well workovers without hydraulic fracturing.

(8) Gas well venting during well workovers with hydraulic fracturing.

(9) Flare stack emissions.

(10) Storage tanks vented emissions from produced hydrocarbons.

(11) Reciprocating compressor rod packing venting.

(12) Well testing venting and flaring.

(13) Associated gas venting and flaring from produced hydrocarbons.

(14) Dehydrator vents.

(15) [Reserved]

(16) EOR injection pump blowdown.

(17) Acid gas removal vents.

(18) EOR hydrocarbon liquids dissolved CO_2.

(19) Centrifugal compressor venting.

(20) [Reserved]

(21) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).

(22) You must use the methods in § 98.233(z) and report under this subpart the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that are located at an onshore production well pad. Stationary or portable equipment are the following equipment which are integral to the extraction, processing or movement of oil or natural gas: Well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(d) For onshore natural gas processing, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Dehydrator vents.

(5) Acid gas removal vents.

(6) Flare stack emissions.

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(e) For onshore natural gas transmission compression, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Transmission storage tanks.

(4) Blowdown vent stacks.

(5) Natural gas pneumatic device venting.

(6) [Reserved]

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(f) For underground natural gas storage, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Natural gas pneumatic device venting.

(4) [Reserved]

(5) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(g) For LNG storage, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Equipment leaks from valves; pump seals; connectors; vapor recovery compressors, and other equipment leak sources.

(h) LNG import and export equipment, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Equipment leaks from valves, pump seals, connectors, vapor recovery compressors, and other equipment leak sources.

(i) For natural gas distribution, report emissions from the following sources:

(1) Above ground meters and regulators at custody transfer city gate stations, including equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Customer meters are excluded.

(2) Above ground meters and regulators at non-custody transfer city gate stations, including station equipment leaks. Customer meters are excluded.

(3) Below ground meters and regulators and vault equipment leaks. Customer meters are excluded.

(4) Pipeline main equipment leaks.

(5) Service line equipment leaks.

(6) Report under subpart W of this part the emissions of CO_2, CH_4, and N_2O emissions from stationary fuel combustion sources following the methods in § 98.233(z).

(j) All applicable industry segments must report the CO_2, CH_4, and N_2O emissions from each flare.

(k) Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of subpart C. Onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in paragraph (c) of this section. Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section.

(l) You must report under subpart PP of this part (Suppliers of Carbon Dioxide), CO_2 emissions captured and transferred off site by following the requirements of subpart PP.

§ 98.233 Calculating GHG emissions.

You must calculate and report the annual GHG emissions as prescribed in this section. For actual conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

(a) *Natural gas pneumatic device venting.* Calculate CH_4 and CO_2 emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices using Equation W–1 of this section.

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24 * 365 \quad \text{(Eq. W-1)}$$

Where:

$Mass_{s,i}$ = Annual total mass GHG emissions in metric tons CO_2e per year at standard conditions from a natural gas pneumatic device vent, for GHG i.

Count = Total number of continuous high bleed, continuous low bleed, or intermittent bleed natural gas pneumatic devices of each type as determined in paragraph (a)(1) of this section.

EF = Population emission factors for natural gas pneumatic device venting listed in Tables W–1A, W–3, and W–4 of this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively.

GHG_i = For onshore petroleum and natural gas production facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas; for facilities listed in § 98.230(a)(3) through (a)(8), GHG_i equals 1.

$Conv_i$ = Conversion from standard cubic feet to metric tons CO_2e; 0.000410 for CH_4, and 0.00005357 for CO_2.

24 * 365 = Conversion to yearly emissions estimate.

(1) For onshore petroleum and natural gas production, provide the total number of continuous high bleed, continuous low bleed, or intermittent bleed natural gas pneumatic devices of each type as follows:

(i) In the first calendar year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(ii) In the second consecutive year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(iii) In the third consecutive calendar year, complete the count of all pneumatic devices, including any changes to equipment counted in prior years.

(iv) For the calendar year immediately following the third consecutive calendar year, and for calendar years thereafter, facilities must update the total count of pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(2) For onshore natural gas transmission compression and underground natural gas storage, all natural gas pneumatic devices must be counted in the first year and updated every calendar year.

(b) [Reserved]

(c) *Natural gas driven pneumatic pump venting.* Calculate CH_4 and CO_2 emissions from natural gas driven pneumatic pump venting using Equation W–2 of this section. Natural gas driven pneumatic pumps covered in paragraph (e) of this section do not have to report emissions under paragraph (c) of this section.

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24 * 365 \quad \text{(Eq. W-2)}$$

Where:

$Mass_{s,i}$ = Annual total mass GHG emissions in metric tons CO_2e per year at standard conditions from all natural gas pneumatic pump venting, for GHG i.

Count = Total number of natural gas pneumatic pumps.

EF = Population emission factors for natural gas pneumatic pump venting listed in Tables W–1A of this subpart for onshore petroleum and natural gas production.

GHG_i = Concentration of GHG i, CH_4 or CO_2, in produced natural gas.

$Conv_i$ = Conversion from standard cubic feet to metric tons CO_2e; 0.000410 for CH_4, and 0.00005357 for CO_2.

24 * 365 = Conversion to yearly emissions estimate.

(d) *Acid gas removal (AGR) vents.* For AGR vent (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or through a flare, engine (*e.g.* permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using any of the calculation methodologies described in paragraph (d) of this section.

(1) *Calculation Methodology 1.* If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part, you must calculate CO_2 emissions under this subpart by following the Tier 4 Calculation Methodology and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If CEMS and/or volumetric flow rate monitor are not available, you may install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion).

(2) *Calculation Methodology 2.* If CEMS is not available, use the CO_2 composition and annual volume of vent gas to calculate emissions using Equation W–3 of this section.

$$E_{a,CO2} = V_S * Vol_{CO2} \quad \text{(Eq. W-3)}$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_S = Total annual volume of vent gas flowing out of the AGR unit in cubic feet per year at actual conditions as determined by flow meter using methods set forth in § 98.234(b).

Vol_{CO2} = Volume fraction of CO_2 content in vent gas out of the AGR unit as determined in (d)(6) of this section.

(3) *Calculation Methodology 3.* If using CEMS or vent meter is not an option, use the inlet or outlet gas flow rate of the acid gas removal unit to calculate emissions for CO_2 using Equation W–4 of this section.

$$E_{a,CO2} = (V + \alpha * (V * (Vol_I - Vol_O))) * (Vol_I - Vol_O) \qquad \text{(Eq. W-4)}$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual condition, in cubic feet per year.

V = Total annual volume of natural gas flow into or out of the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (d)(5) of this section.

α = Factor is 1 if the outlet stream flow is measured. Factor is 0 if the inlet stream flow is measured.

Vol_I = Volume fraction of CO_2 content in natural gas into the AGR unit as determined in paragraph (d)(7) of this section.

Vol_O = Volume fraction of CO_2 content in natural gas out of the AGR unit as determined in paragraph (d)(8) of this section.

(4) *Calculation Methodology 4.* Calculate emissions using any standard simulation software packages, such as AspenTech HYSYS® and API 4679 AMINECalc, that uses the Peng-Robinson equation of state, and speciates CO_2 emissions. A minimum of the following determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best available data must be used to characterize emissions:

(i) Natural gas feed temperature, pressure, and flow rate.

(ii) Acid gas content of feed natural gas.

(iii) Acid gas content of outlet natural gas.

(iv) Unit operating hours, excluding downtime for maintenance or standby.

(v) Exit temperature of natural gas.

(vi) Solvent pressure, temperature, circulation rate, and weight.

(5) Record the gas flow rate of the inlet and outlet natural gas stream of an AGR unit using a meter according to methods set forth in § 98.234(b). If you do not have a continuous flow meter, either install a continuous flow meter or use an engineering calculation to determine the flow rate.

(6) If continuous gas analyzer is not available on the vent stack, either install a continuous gas analyzer or take quarterly gas samples from the vent gas stream to determine Vol_{CO2} according to methods set forth in § 98.234(b).

(7) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If continuous gas analyzer is not available, either install a continuous gas analyzer or take quarterly gas samples from the inlet gas stream to determine Vol_I according to methods set forth in § 98.234(b).

(8) Determine volume fraction of CO_2 content in natural gas out of the AGR unit using one of the methods specified in paragraph (d)(8) of this section.

(i) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, you may install a continuous gas analyzer.

(ii) If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet gas stream to determine Vol_O according to methods set forth in § 98.234(b).

(iii) Use sales line quality specification for CO_2 in natural gas.

(9) Calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(10) Mass CO_2 emissions shall be calculated from volumetric CO_2 emissions using calculations in paragraph (v) of this section.

(11) Determine if emissions from the AGR unit are recovered and transferred outside the facility. Adjust the emission estimated in paragraphs (d)(1) through (d)(10) of this section downward by the magnitude of emission recovered and transferred outside the facility.

(e) *Dehydrator vents.* For dehydrator vents, calculate annual CH_4, CO_2 and N_2O (when flared) emissions using calculation methodologies described in paragraphs (e)(1) or (e)(2) of this section.

(1) *Calculation Methodology 1.* Calculate annual mass emissions from dehydrator vents with throughput greater than or equal to 0.4 million standard cubic feet per day using a software program, such as AspenTech HYSYS® or GRI–GLYCalc, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. A minimum of the following parameters determined by engineering estimate based on best available data must be used to characterize emissions from dehydrators:

(i) Feed natural gas flow rate.

(ii) Feed natural gas water content.

(iii) Outlet natural gas water content.

(iv) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).

(v) Absorbent circulation rate.

(vi) Absorbent type: including triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).

(vii) Use of stripping natural gas.

(viii) Use of flash tank separator (and disposition of recovered gas).

(ix) Hours operated.

(x) Wet natural gas temperature and pressure.

(xi) Wet natural gas composition. Determine this parameter by selecting one of the methods described under paragraph (e)(2)(xi) of this section.

(A) Use the wet natural gas composition as defined in paragraph (u)(2)(i) of this section.

(B) If wet natural gas composition cannot be determined using paragraph (u)(2)(i) of this section, select a representative analysis.

(C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in § 98.234(b)(1) to sample and analyze wet natural gas composition.

(D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) *Calculation Methodology 2.* Calculate annual CH_4 and CO_2 emissions from glycol dehydrators with throughput less than 0.4 million cubic feet per day using Equation W–5 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-5)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factors for glycol dehydrators in thousand standard cubic feet per dehydrator per year. Use 74.5 for CH_4 and 3.26 for CO_2 at 68°F and 14.7 psia or 73.4 for CH_4 and 3.21 for CO_2 at 60°F and 14.7 psia.

Count = Total number of glycol dehydrators with throughput less than 0.4 million cubic feet.

1000 = Conversion of EF_i in thousand standard cubic to cubic feet.

(3) Determine if dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (e)(1) or (e)(2) of this section downward by the magnitude of emissions captured.

(4) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:

(A) Use the dehydrator vent volume and gas composition as determined in paragraphs (e)(1) and (e)(2) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(5) Dehydrators that use desiccant shall calculate emissions from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using Equation W–6 of this section. Desiccant dehydrators covered in (e)(5) of this section do not have to report emissions under (i) of this section.

$$E_{s,n} = \frac{(H*D^2*P*P_2*\%G*365days/yr)}{(4*P_1*T*1{,}000cf/Mcf*100)} \qquad \text{(Eq. W-6)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions in cubic feet.
H = Height of the dehydrator vessel (ft).
D = Inside diameter of the vessel (ft).
P_1 = Atmospheric pressure (psia).
P_2 = Pressure of the gas (psia).
P = pi (3.14).
%G = Percent of packed vessel volume that is gas.
T = Time between refilling (days).
100 = Conversion of %G to fraction.

(6) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(f) *Well venting for liquids unloadings.* Calculate CO_2 and CH_4 emissions from well venting for liquids unloading using one of the calculation methodologies described in paragraphs (f)(1), (f)(2) or (f)(3) of this section.

(1) *Calculation Methodology 1.* For one well of each unique well tubing diameter and producing horizon/formation combination in each gas producing field (see § 98.238 for the definition of Field) where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, a recording flow meter shall be installed on the vent line used to vent gas from the well (*e.g.* on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in § 98.234(b). Calculate emissions from well venting for liquids unloading using Equation W–7 of this section.

$$E_{a,n} = \sum_h \sum_t T_{h,t} * FR_{h,t} \qquad \text{(Eq. W-7)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions in cubic feet.
$T_{h,t}$ = Cumulative amount of time in hours of venting from all wells of the same tubing diameter (t) and producing horizon (h)/formation combination during the year.
$FR_{h,t}$ = Average flow rate in cubic feet per hour of the measured well venting for the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

(i) Determine the well vent average flow rate as specified under paragraph (f)(1)(i) of this section.

(A) The average flow rate per hour of venting is calculated for each unique tubing diameter and producing horizon/formation combination in each producing field by averaging the recorded flow rates for the recorded time of one representative well venting to the atmosphere.

(B) This average flow rate is applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination, for the number of hours of venting these wells.

(C) A new average flow rate is calculated every other calendar year for each reporting field and horizon starting the first calendar year of data collection.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) *Calculation Methodology 2.* Calculate emissions from each well venting for liquids unloading using Equation W–8 of this section.

$$E_{a,n} = \{(0.37\times10^{-3})*CD^2*WD*SP*N_V\}+\{SFR*(HR-1.0)*Z\} \qquad \text{(Eq. W-8)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions, in cubic feet/year.
0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).
CD = Casing diameter (inches).
WD = Well depth to first producing horizon (feet).
SP = Shut-in pressure (psia).
N_V = Number of vents per year.
SFR = Average sales flow rate of gas well in cubic feet per hour.
HR = Hours that the well was left open to the atmosphere during unloading.
1.0 = Hours for average well to blowdown casing volume at shut-in pressure.
Z = If HR is less than 1.0 then Z is equal to 0. If HR is greater than or equal to 1.0 then Z is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(3) *Calculation Methodology 3.* Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W–9 of this section.

$$E_{a,n} = \{(0.37\times10^{-3})*TD^2*WD*SP*N_V\}+\{SFR*(HR-0.5)*Z\} \qquad \text{(Eq. W-9)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions, in cubic feet/year.

0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

TD = Tubing diameter (inches).

WD = Tubing depth to plunger bumper (feet).

SP = Sales line pressure (psia).

N_V = Number of vents per year.

SFR = Average sales flow rate of gas well in cubic feet per hour.

HR = Hours that the well was left open to the atmosphere during unloading.

0.5 = Hours for average well to blowdown tubing volume at sales line pressure.

Z = If HR is less than 0.5 then Z is equal to 0. If HR is greater than or equal to 0.5 then Z is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(g) *Gas well venting during completions and workovers from hydraulic fracturing.* Calculate CH_4, CO_2 and N_2O (when flared) annual emissions from gas well venting during completions involving hydraulic fracturing in wells and well workovers using Equation W–10 of this section. Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total gas emissions using calculations in paragraphs (u) and (v) of this section.

$$E_{a,n} = (T * FR) - EnF - SG \qquad \text{(Eq. W-10)}$$

Where:

$E_{a,n}$ = Annual volumetric total gas emissions in cubic feet at standard conditions from gas well venting during completions following hydraulic fracturing.

T = Cumulative amount of time in hours of all well completion venting in a field during the year reporting.

FR = Average flow rate in cubic feet per hour, under actual conditions, converted to standard conditions, as required in paragraph (g)(1) of this section.

EnF = Volume of CO_2 or N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job. If the fracture process did not inject gas into the reservoir, then EnF is 0. If injected gas is CO_2 then EnF is 0.

SG = Volume of natural gas in cubic feet at standard conditions that was recovered into a sales pipeline. If no gas was recovered for sales, SG is 0.

(1) The average flow rate for gas well venting to the atmosphere or to a flare during well completions and workovers from hydraulic fracturing shall be determined using either of the calculation methodologies described in this paragraph (g)(1) of this section.

(i) *Calculation Methodology 1.* For one well completion in each gas producing field and for one well workover in each gas producing field, a recording flow meter (digital or analog) shall be installed on the vent line, ahead of a flare if used, to measure the backflow venting event according to methods set forth in § 98.234(b).

(A) The average flow rate in cubic feet per hour of venting to the atmosphere or routed to a flare is determined from the flow recording over the period of backflow venting.

(B) The respective flow rates are applied to all well completions in the producing field and to all well workovers in the producing field for the total number of hours of venting of each of these wells.

(C) New flow rates for completions and workovers are measured every other calendar year for each reporting gas producing field and gas producing geologic horizon in each gas producing field starting in the first calendar year of data collection.

(D) Calculate total volumetric flow rate at standard conditions using calculations in paragraph (t) of this section.

(ii) *Calculation Methodology 2.* For one well completion in each gas producing field and for one well workover in each gas producing field, record the well flowing pressure upstream (and downstream in subsonic flow) of a well choke according to methods set forth in § 98.234(b) to calculate intermittent well flow rate of gas during venting to the atmosphere or a flare. Calculate emissions using Equation W–11 of this section for subsonic flow or Equation W–12 of this section for sonic flow:

$$FR = 1.27*10^5 * A * \sqrt{3430 * T_u * \left[\left(\frac{P_2}{P_1}\right)^{1.515} - \left(\frac{P_2}{P_1}\right)^{1.758}\right]} \qquad \text{(Eq. W-11)}$$

Where:

FR = Average flow rate in cubic feet per hour, under subsonic flow conditions.

A = Cross sectional area of orifice (m^2).

P_1 = Upstream pressure (psia).

T_u = Upstream temperature (degrees Kelvin).

P_2 = Downstream pressure (psia).

3430 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

$$FR = 1.27*10^5 * A * \sqrt{187.08 * T_u} \qquad \text{(Eq. W-12)}$$

Where:

FR = Average flow rate in cubic feet per hour, under sonic flow conditions.

A = Cross sectional area of orifice (m^2).

T_u = Upstream temperature (degrees Kelvin).

187.08 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

(A) The average flow rate in cubic feet per hour of venting across the choke is calculated for one well completion in each gas producing field and for one well workover in each gas producing field by averaging the gas flow rates during venting to the atmosphere or routing to a flare.

(B) The respective flow rates are applied to all well completions in the gas producing field and to all well workovers in the gas producing field for the total number of hours of venting of each of these wells.

(C) Flow rates for completions and workovers in each field shall be calculated once every two years for each reporting gas producing field and geologic horizon in each gas producing field starting in the first calendar year of data collection.

(D) Calculate total volumetric flow rate at standard conditions using calculations in paragraph (t) of this section.

(2) The volume of CO_2 or N_2 injected into the well reservoir during energized hydraulic fractures will be measured using an appropriate meter as described in 98.234(b) or using receipts of gas purchases that are used for the energized fracture job.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(3) The volume of recovered completion gas sent to a sales line will be measured using existing company records. If data does not exist on sales gas, then an appropriate meter as described in 98.234(b) may be used.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total emissions using calculations in paragraphs (u) and (v) of this section.

(5) Determine if the well completion or workover from hydraulic fracturing recovered gas with purpose designed equipment that separates saleable gas from the backflow, and sent this gas to a sales line (*e.g.* reduced emissions completion).

(i) Use the factor SG in Equation W–10 of this section, to adjust the emissions estimated in paragraphs (g)(1) through (g)(4) of this section by the magnitude of emissions captured using reduced emission completions as determined by engineering estimate based on best available data.

(ii) [Reserved]

(6) Calculate annual emissions from gas well venting during well completions and workovers from hydraulic fracturing to flares as follows:

(i) Use the total gas well venting volume during well completions and workovers as determined in paragraph (g) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers using hydraulic fracturing emissions from the flare. This adjustment to emissions from completions using flaring versus completions without flaring accounts for the conversion of CH_4 to CO_2 in the flare.

(h) *Gas well venting during completions and workovers without hydraulic fracturing.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from each gas well venting during well completions and workovers not involving hydraulic fracturing and well workovers not involving hydraulic fracturing using Equation W–13 of this section:

$$E_{a,n} = N_{wo} * EF_{wo} + \sum_{f} V_f * T_f \qquad \text{(Eq. W-13)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions in cubic feet at actual conditions from gas well venting during well completions and workovers without hydraulic fracturing.

N_{wo} = Number of workovers per field not involving hydraulic fracturing in the reporting year.

EF_{wo} = Emission Factor for non-hydraulic fracture well workover venting in actual cubic feet per workover. EF_{wo} = 2,454 standard cubic feet per well workover without hydraulic fracturing.

f = Total number of well completions without hydraulic fracturing in a field.

V_f = Average daily gas production rate in cubic feet per hour of each well completion without hydraulic fracturing. This is the total annual gas production volume divided by total number of hours the wells produced to the sales line. For completed wells that have not established a production rate, you may use the average flow rate from the first 30 days of production. In the event that the well is completed less than 30 days from the end of the calendar year, the first 30 days of the production straddling the current and following calendar years shall be used.

T_f = Time each well completion without hydraulic fracturing was venting in hours during the year.

(1) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(3) Calculate annual emissions from gas well venting during well completions and workovers not involving hydraulic fracturing to flares as follows:

(i) Use the gas well venting volume during well completions and workovers as determined in paragraph (h) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers emissions without hydraulic fracturing from the flare.

(i) *Blowdown vent stacks.* Calculate CO_2 and CH_4 blowdown vent stack emissions from depressurizing equipment to the atmosphere (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (e)(5) of this section) as follows:

(1) Calculate the total volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves determined by engineering estimate based on best available data.

(2) If the total volume between isolation valves is greater than or equal to 50 standard cubic feet, retain logs of the number of blowdowns for each equipment type (including but not limited to compressors, vessels, pipelines, headers, fractionators, and tanks). Blowdown volumes smaller than 50 standard cubic feet are exempt from reporting under paragraph (i) of this section.

(3) Calculate the total annual venting emissions for each equipment type using Equation W–14 of this section:

$$E_{s,n} = N * \left(V_v \left(\frac{(459.67 + T_s)P_a}{(459.67 + T_a)P_s} \right) - V_v * C \right) \qquad \text{(Eq. W-14)}$$

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.
N = Number of repetitive blowdowns for each equipment type of a unique volume in calendar year.
V_v = Total volume of blowdown equipment chambers (including pipelines, compressors and vessels) between isolation valves in cubic feet.
C = Purge factor that is 1 if the equipment is not purged or zero if the equipment is purged using non-GHG gases.
T_s = Temperature at standard conditions (°F).
T_a = Temperature at actual conditions in the blowdown equipment chamber (°F).
P_s = Absolute pressure at standard conditions (psia).
P_a = Absolute pressure at actual conditions in the blowdown equipment chamber (psia).

(4) Calculate both CH_4 and CO_2 mass emissions from volumetric natural gas emissions using calculations in paragraph (v) of this section.

(5) Calculate total annual venting emissions for all blowdown vent stacks by adding all standard volumetric and mass emissions determined in Equation W–14 and paragraph (i)(4) of this section.

(j) *Onshore production storage tanks.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned or operated by the reporter), calculate annual CH_4 and CO_2 emissions using any of the calculation methodologies described in this paragraph (j).

(1) *Calculation Methodology 1.* For separators with oil throughput greater than or equal to 10 barrels per day. Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks using operating conditions in the last wellhead gas-liquid separator before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the oil from the separator enters an atmospheric pressure storage tank. A minimum of the following parameters determined for typical operating conditions over the year by engineering estimate and process knowledge based on best available data must be used to characterize emissions from liquid transferred to tanks.

(i) Separator temperature.

(ii) Separator pressure.

(iii) Sales oil or stabilized oil API gravity.

(iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Separator oil composition and Reid vapor pressure. If this data is not available, determine these parameters by selecting one of the methods described under paragraph (j)(1)(viii) of this section.

(A) If separator oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator pressure first, and API gravity secondarily.

(B) If separator oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the field.

(C) Analyze a representative sample of separator oil in each field for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Methodology 2.* Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks for wellhead gas-liquid separators with oil throughput greater than or equal to 10 barrels per day by assuming that all of the CH_4 and CO_2 in solution at separator temperature and pressure is emitted from oil sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in § 98.234(b)(1) to sample and analyze separator oil composition at separator pressure and temperature.

(3) *Calculation Methodology 3.* For wells with oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks without passing through a wellhead separator, calculate CH_4 and CO_2 emissions by either of the methods in paragraph (j)(3) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of produced oil and gas from the field and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(ii) If well production oil and gas compositions are not available, use default oil and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match your well production gas/oil ratio and API gravity and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(4) *Calculation Methodology 4.* For wells with oil production greater than or equal to 10 barrels per day that flow to a separator not at the well pad, calculate CH_4 and CO_2 emissions by either of the methods in paragraph (j)(4) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of oil at separator pressure determined by best available data and assume all of the CH_4 and CO_2 in the oil is emitted from the tank.

(ii) If well production oil composition is not available, use default oil composition in software programs, such as API 4697 E&P Tank, that most closely match your well production API gravity and pressure in the off-well pad separator determined by best available data. Assume all of the CH_4 and CO_2 in the oil phase is emitted from the tank.

(5) *Calculation Methodology 5.* For well pad gas-liquid separators and for wells flowing off a well pad without passing through a gas-liquid separator with throughput less than 10 barrels per day use Equation W–15 of this section:

$$E_{s,i} = EF_i * Count \quad \text{(Eq. W-15)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.
EF_i = Populations emission factor for separators and wells in thousand standard cubic feet per separator or well per year, for crude oil use 4.3 for CH_4 and 2.9 for CO_2 at 68 °F and 14.7 psia, and for gas condensate use 17.8 for CH_4 and 2.9 for CO_2 at 68 °F and 14.7 psia.
Count = Total number of separators and wells with throughput less than 10 barrels per day.

(6) Determine if the storage tank receiving your separator oil has a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (j)(1) through (j)(5) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(7) Determine if the storage tank receiving your separator oil is sent to flare(s).

(i) Use your separator flash gas volume and gas composition as determined in this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine your contribution to storage tank emissions from the flare.

(8) Calculate emissions from occurrences of well pad gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W–16 of this section.

$$E_{s,i} = \left(CF_n * E_n * T_n\right) + \left(E_t * \left(8760 - T_n\right)\right) \quad \text{(Eq. W-16)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each storage tank in cubic feet.

E_n = Storage tank emissions as determined in Calculation Methodologies 1, 2, or 5 in paragraphs (j)(1) through (j)(5) of this section (with wellhead separators) during time T_n in cubic feet per hour.

T_n = Total time the dump valve is not closing properly in the calendar year in hours. T_n is estimated by maintenance or operations records (records) such that when a record shows the valve to be open improperly, it is assumed the valve was open for the entire time period preceding the record starting at either the beginning of the calendar year or the previous record showing it closed properly within the calendar year. If a subsequent record shows it is closing properly, then assume from that time forward the valve closed properly until either the next record of it not closing properly or, if there is no subsequent record, the end of the calendar year.

CF_n = Correction factor for tank emissions for time period T_n is 3.87 for crude oil production. Correction factor for tank emissions for time period T_n is 5.37 for gas condensate production. Correction factor for tank emissions for time period T_n is 1.0 for periods when the dump valve is closed.

E_t = Storage tank emissions as determined in Calculation Methodologies 1, 2, or 3 in paragraphs (j)(1) through (j)(5) of this section at maintenance or operations during the time the dump valve is closing properly (ie. 8760–T_n) in cubic feet per hour.

(9) Calculate both CH_4 and CO_2 mass emissions from volumetric natural gas emissions using calculations in paragraph (v) of this section.

(k) *Transmission storage tanks.* For condensate storage tanks, either water or hydrocarbon, without vapor recovery or thermal control devices in onshore natural gas transmission compression facilities calculate CH_4, CO_2 and N_2O (when flared) annual emissions from compressor scrubber dump valve leakage as follows:

(1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in § 98.234(a)(1) for a duration of 5 minutes. Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(2) If the tank vapors are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (k)(2) of this section to quantify emissions:

(i) Use a meter, such as a turbine meter, to estimate tank vapor volumes according to methods set forth in § 98.234(b). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack.

(ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in § 98.234(a)(5).

(iii) Use the appropriate gas composition in paragraph (u)(2)(iii) of this section.

(3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.

(4) Calculate emissions from storage tanks to flares as follows:

(i) Use the storage tank emissions volume and gas composition as determined in either paragraph (j)(1)of this section or with an acoustic leak detection device in paragraphs (k)(1) through (k)(3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine storage tank emissions from the flare.

(l) *Well testing venting and flaring.* Calculate CH_4, CO_2 and N_2O (when flared) well testing venting and flaring emissions as follows:

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from each well tested.

(2) If GOR cannot be determined from your available data, then you must measure quantities reported in this section according to one of the two procedures in paragraph (l)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in § 98.234(b).

(3) Estimate venting emissions using Equation W–17 of this section.

$$E_{a,n} = GOR * FR * D \quad \text{(Eq. W-17)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from well testing in cubic feet under actual conditions.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

FR = Flow rate in barrels of oil per day for the well being tested.

D = Number of days during the year, the well is tested.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from well testing to flares as follows:

(i) Use the well testing emissions volume and gas composition as determined in paragraphs (l)(1) through (3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine well testing emissions from the flare.

(m) *Associated gas venting and flaring.* Calculate CH_4, CO_2 and N_2O (when flared) associated gas venting and flaring emissions not in conjunction with well testing (refer to paragraph (l): Well testing venting and flaring of this section) as follows:

(1) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, the GOR from a cluster of wells in the same field shall be used.

(2) If GOR cannot be determined from your available data, then use one of the two procedures in paragraph (m)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in § 98.234(b).

(3) Estimate venting emissions using Equation W–18 of this section.

$$E_{a,n} = GOR * V \quad \text{(Eq. W-18)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from associated gas venting under actual conditions, in cubic feet.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

V = Volume of oil produced in barrels in the calendar year during which associated gas was vented or flared.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from associated natural gas to flares as follows:

(i) Use the associated natural gas volume and gas composition as determined in paragraph (m)(1) through (4) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine associated gas emissions from the flare.

(n) *Flare stack emissions.* Calculate CO_2, CH_4, and N_2O emissions from a flare stack as follows:

(1) If you have a continuous flow measurement device on the flare, you must use the measured flow volumes to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can install a flow measuring device on the flare or use engineering calculations based on process knowledge, company records, and best available data.

(2) If you have a continuous gas composition analyzer on gas to the flare, you must use these compositions in calculating emissions. If you do not have a continuous gas composition analyzer on gas to the flare, you must use the appropriate gas compositions for each stream of hydrocarbons going to the flare as follows:

(i) For onshore natural gas production, determine natural gas composition using (u)(2)(i) of this section.

(ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities.

(iii) When the stream going to the flare is a hydrocarbon product stream, such as ethane, propane, butane, pentane-plus and mixed light hydrocarbons, then use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Calculate GHG volumetric emissions at actual conditions using Equations W–19, W–20, and W–21 of this section.

$$E_{a,CH4}(un-combusted) = V_a * (1-\eta) * X_{CH4} \quad \text{(Eq. W-19)}$$

$$E_{a,CO2}(un-combusted) = V_a * X_{CO2} \quad \text{(Eq. W-20)}$$

$$E_{a,CO2}(combusted) = \sum_j \eta * V_a * Y_j * R_j \quad \text{(Eq. W-21)}$$

Where:

E_{a,CH_4}(un-combusted) = Contribution of annual un-combusted CH_4 emissions from flare stack in cubic feet, under actual conditions.

E_{a,CO_2}(un-combusted) = Contribution of annual un-combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.

E_{a,CO_2}(combusted) = Contribution of annual combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.

V_a = Volume of gas sent to flare in cubic feet, during the year.

η = Fraction of gas combusted by a burning flare (default is 0.98). For gas sent to an unlit flare, η is zero.

X_{CH_4} = Mole fraction of CH_4 in gas to the flare.

X_{CO_2} = Mole fraction of CO_2 in gas to the flare.

Y_j = Mole fraction of gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus).

R_j = Number of carbon atoms in the gas hydrocarbon constituent j: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus).

(5) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(7) Calculate total annual emission from flare stacks by summing Equation W–40, Equation W–19, Equation W–20 and Equation W–21 of this section.

(8) Calculate N_2O emissions from flare stacks using Equation W–40 in paragraph (z) of this section.

(9) The flare emissions determined under paragraph (n) of this section must be corrected for flare emissions calculated and reported under other paragraphs of this section to avoid double counting of these emissions.

(o) *Centrifugal compressor venting.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents as follows:

(1) For each centrifugal compressor covered by § 98.232 (d)(2), (e)(2), (f)(2), (g)(2), and (h)(2) you must conduct an annual measurement in the operating mode in which it is found. Measure emissions from all vents (including emissions manifolded to common vents)

including wet seal oil degassing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement.

(i) Operating mode, blowdown valve leakage through the blowdown vent, wet seal and dry seal compressors.

(ii) Operating mode, wet seal oil degassing vents.

(iii) Not operating, depressurized mode, unit isolation valve leakage through open blowdown vent, without blind flanges, wet seal and dry seal compressors.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(2) For wet seal oil degassing vents, determine vapor volumes sent to an atmospheric vent or flare, using a temporary meter such as a vane anemometer or permanent flow meter according to 98.234(b) of this section. If you do not have a permanent flow meter, you may install a permanent flow meter on the wet seal oil degassing tank vent.

(3) For blowdown valve leakage and unit isolation valve leakage to open ended vents, you can use one of the following methods: Calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and § 98.234(d), respectively. For through valve leakage, such as isolation valves, you may use an acoustic leak detection device according to methods set forth in § 98.234(a). If you do not have a flow meter, you may install a port for insertion of a temporary meter, or a permanent flow meter, on the vents.

(4) Estimate annual emissions using the flow measurement and Equation W–22 of this section.

$$E_{s,i,m} = MT_m * T_m * M_{i,m} * (1 - B_m) \quad \text{(Eq. W-22)}$$

Where:

$E_{s,i,m}$ = Annual GHG_i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour.

T_m = Total time the compressor is in the mode for which $E_{s,i}$ is being calculated, in the calendar year in hours.

$M_{i,m}$ = Mole fraction of GHG_i in the vent gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

B_m = Fraction of operating time that the vent gas is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the time that vent gas is directed to the fuel gas system or sales.

(5) Calculate annual emissions from each centrifugal compressor using Equation W–23 of this section.

$$E_{s,i} = \sum_m EF_m * T_m * GHG_i \quad \text{(Eq. W-23)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each centrifugal compressor in cubic feet.

EF_m = Reporter emission factor for each mode m, in cubic feet per hour, from Equation W–24 of this section as calculated in paragraph 6.

T_m = Total time in hours per year the compressor was in each mode, as listed in paragraph (o)(1)(i) through (o)(1)(iii).

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1.

(6) You shall use the flow measurements of operating mode wet seal oil degassing vent, operating mode blowdown valve vent and not operating depressurized mode isolation valve vent for all the reporter's compressor modes not measured in the calendar year to develop the following emission factors using Equation W–24 of this section for each emission source and mode as listed in paragraph (o)(1)(i) through (o)(1)(iii).

$$EF_m = \sum \frac{MT_m}{Count_m} \quad \text{(Eq. W-24)}$$

Where:

EF_m = Reporter emission factors for compressor in the three modes m (as listed in paragraph (o)(1)(i) through (o)(1)(iii)) in cubic feet per hour.

MT_m = Flow Measurements from all centrifugal compressor vents in each mode in (o)(1)(i) through (o)(1)(iii) of this section in cubic feet per hour.

$Count_m$ = Total number of compressors measured.

m = Compressor mode as listed in paragraph (o)(1)(i) through (o)(1)(iii).

(i) The emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding two calendar years, totaling three consecutive calendar years of measurements in paragraph (o)(6) of this section.

(ii) [Reserved]

(7) Onshore petroleum and natural gas production shall calculate emissions from centrifugal compressor wet seal oil degassing vents as follows:

$$E_{s,i} = Count * EF_i \quad \text{(Eq. W-25)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from centrifugal compressor wet seals in cubic feet.

Count = Total number of centrifugal compressors for the reporter.

EF_i = Emission factor for GHG $_i$. Use 12.2 million standard cubic feet per year per compressor for CH_4 and 538 thousand standard cubic feet per year per compressor for CO_2 at 68°F and 14.7 psia or 12 million standard cubic feet per year per compressor for CH_4 and 530 thousand standard cubic feet per year per compressor for CO_2 at 60°F and 14.7 psia.

(8) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(9) Calculate emissions from seal oil degassing vent vapors to flares as follows:

(i) Use the seal oil degassing vent vapor volume and gas composition as determined in paragraphs (o)(5) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine degassing vent vapor emissions from the flare.

(p) *Reciprocating compressor venting.* Calculate CH_4 and CO_2 emissions from all reciprocating compressor vents as follows. For each reciprocating compressor covered in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1) you must conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement, except as specified in paragraph (p)(9) of this section. Measure emissions from (including emissions manifolded to common vents) reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement as follows:

(1) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.

(2) Operating mode, reciprocating rod packing emissions.

(3) Not operating, depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.

(i) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(ii) [Reserved]

(4) If reciprocating rod packing and blowdown vent are connected to an open-ended vent line use one of the following two methods to calculate emissions:

(i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and § 98.234(d), respectively.

(ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents and unit isolation valve leakage through blowdown vents according to methods set forth in § 98.234(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents, such as unit isolation valves on not operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in § 98.234(a).

(5) If reciprocating rod packing is not equipped with a vent line use the following method to calculate emissions:

(i) You must use the methods described in § 98.234(a) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or other vent with a closed distance piece.

(ii) Measure emissions found in paragraph (p)(5)(i) of this section using an appropriate meter, or calibrated bag, or high volume sampler according to methods set forth in § 98.234(b), (c), and (d), respectively.

(6) Estimate annual emissions using the flow measurement and Equation W–26 of this section.

$$E_{s,i,m} = MT_m * T_m * M_{i,m} \quad \text{(Eq. W-26)}$$

Where:

$E_{s,i,m}$ = Annual GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour.

T_m = Total time the compressor is in the mode for which $E_{s,i,m}$ is being calculated, in the calendar year in hours.

$M_{i,m}$ = Mole fraction of GHG i in gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

(7) Calculate annual emissions from each reciprocating compressor using Equation W–27 of this section.

$$E_{s,i} = \sum_m EF_m * T_m * GHG_i \quad \text{(Eq. W-27)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each reciprocating compressor in cubic feet.

EF_m = Reporter emission factor for each mode, m, in cubic feet per hour, from Equation W–28 of this section as calculated in paragraph (p)(7)(i) of this section.

T_m = Total time in hours per year the compressor was in each mode, m, as listed in paragraph (p)(1) through (p)(3).

GHG_i = For onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1.

m = Compressor mode as listed in paragraph (p)(1) through (p)(3).

(i) You shall use the flow meter readings from measurements of operating and standby pressurized blowdown vent, operating mode vents, not operating depressurized isolation valve vent for all the reporter's compressor modes not measured in the calendar year to develop the following emission factors using Equation W–28 of this section for each mode as listed in paragraph (p)(1) through (p)(3).

$$EF_m = \sum \frac{MT_m}{Count_m} \quad \text{(Eq. W-28)}$$

Where:

EF_m = Reporter emission factors for compressor in the three modes, m, in cubic feet per hour.

MT_m = Meter readings from all reciprocating compressor vents in each and mode, m, in cubic feet per hour.

$Count_m$ = Total number of compressors measured in each mode, m.

m = Compressor mode as listed in paragraph (p)(1) through (p)(3).

(A) You must combine emissions for blowndown vents, measured in the operating and standby pressurized modes.

(B) The emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding two calendar years, totaling three consecutive calendar years of measurements.

(ii) [Reserved]

(8) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (p)(7) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(9) Onshore petroleum and natural gas production shall calculate emissions from reciprocating compressors as follows:

$$E_{s,i} = Count * EF_i \quad \text{(Eq. W-29)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from reciprocating compressors in cubic feet.

Count = Total number of reciprocating compressors for the reporter.

EF_i = Emission factor for GHG i. Use 9.63 thousand standard cubic feet per year per compressor for CH_4 and 0.535 thousand standard cubic feet per year per compressor for CO_2 at 68°F and 14.7 psia or 9.48 thousand standard cubic feet per year per compressor for CH_4 and 0.527 thousand standard cubic feet per year per compressor for CO_2 at 60°F and 14.7 psia.

(10) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (u) and (v) of this section.

(q) *Leak detection and leaker emission factors.* You must use the methods described in § 98.234(a) to conduct leak detection(s) of equipment leaks from all sources listed in § 98.232(d)(7), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1). This paragraph (q) applies to emissions sources in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported. If equipment leaks are detected for sources listed in this paragraph (q), calculate emissions using Equation W–30 of this section for each source with equipment leaks.

$$E_{s,i} = GHG_i * \sum_x EF_s * T_x \quad \text{(Eq. W-30)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each equipment leak source in cubic feet.

x = Total number of this type of emissions source found to be leaking during T_x.

EF_s = Leaker emission factor for specific sources listed in Table W–2 through Table W–7 of this subpart.

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2.

T_x = The total time the component was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey or the beginning of the calendar year. For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.

(1) You must select to conduct either one leak detection survey in a calendar year or multiple complete leak detection surveys in a calendar year. The number of leak detection surveys selected must be conducted during the calendar year.

(2) Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions using calculations in paragraph (v) of this section.

(3) Onshore natural gas processing facilities shall use the appropriate default leaker emission factors listed in Table W–2 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(4) Onshore natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table W–3 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(5) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table W–4 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(6) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table W–5 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(7) LNG import and export facilities shall use the appropriate default leaker emission factors listed in Table W–6 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(8) Natural gas distribution facilities for above ground meters and regulators at city gate stations at custody transfer, shall use the appropriate default leaker emission factors listed in Table W–7 of this subpart for equipment leak detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines.

(r) *Population count and emission factors.* This paragraph applies to emissions sources listed in § 98.232 (c)(21), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3), (i)(4) and (i)(5), on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. Calculate emissions from all sources listed in this paragraph using Equation W–31 of this section.

$$E_{s,i} = Count_s * EF_s * GHG_i * T_s \quad \text{(Eq. W-31)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG emissions at standard conditions from each equipment leak source in cubic feet.

$Count_s$ = Total number of this type of emission source at the facility. Average component counts are provided by major equipment piece in Tables W–1B and Table W–1C of this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W–1D of this subpart.

EF_s = Population emission factor for the specific source, s listed in Table W–1A and Tables W–3 through Table W–7 of this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W–1D of this subpart. EF for non-custody transfer city gate stations is determined in Equation W–32.

GHG_i = For onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2.

T_s = Total time the specific source s associated with the equipment leak emission was operational in the calendar year, in hours.

(1) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(2) Onshore petroleum and natural gas production facilities shall use the appropriate default population emission factors listed in Table W–1A of this subpart for equipment leaks from valves, connectors, open ended lines, pressure relief valves, pump, flanges, and other. Major equipment and components associated with gas wells are considered gas service components in reference to Table 1–A of this subpart and major natural gas equipment in reference to Table W–1B of this subpart. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table 1–A of this subpart and major crude oil equipment in reference to Table W–1C of this subpart. Where facilities conduct EOR operations the emissions factor listed in Table W–1A of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. The component count can be determined using either of the methodologies described in this paragraph (r)(2). The same methodology must be used for the entire calendar year.

(i) *Component Count Methodology 1.* For all onshore petroleum and natural gas production operations in the facility perform the following activities:

(A) Count all major equipment listed in Table W–1B and Table W–1C of this subpart.

(B) Multiply major equipment counts by the average component counts listed in Table W–1B and W–1C of this subpart for onshore natural gas production and onshore oil production, respectively. Use the appropriate factor in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

(ii) *Component Count Methodology 2.* Count each component individually for the facility. Use the appropriate factor in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

(3) Underground natural gas storage facilities for storage wellheads shall use the appropriate default population emission factors listed in Table W–4 of this subpart for equipment leak from connectors, valves, pressure relief valves, and open ended lines.

(4) LNG storage facilities shall use the appropriate default population emission factors listed in Table W–5 of this subpart for equipment leak from vapor recovery compressors.

(5) LNG import and export facilities shall use the appropriate default population emission factor listed in Table W–6 of this subpart for equipment leak from vapor recovery compressors.

(6) Natural gas distribution facilities shall use the appropriate emission factors as described in paragraph (r)(6) of this section.

(i) Below grade meters and regulators; mains; and services, shall use the appropriate default population emission factors listed in Table W–7 of this subpart.

(ii) Above grade meters and regulators at city gate stations not at custody transfer as listed in § 98.232(i)(2), shall use the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in paragraph (q)(8) of this section to develop facility emission factors using Equation W–32 of this section. The calculated facility emission factor from Equation W–32 of this section shall be used in Equation W–31 of this section.

$$EF = \sum \frac{E_{s,i}}{Count} \quad \text{(Eq. W-32)}$$

Where:

EF = Facility emission factor for a meter at above grade M&R at city gate stations not at custody transfer in cubic feet per meter per year.

$E_{s,i}$ = Annual volumetric GHG emissions at standard condition from all equipment leak sources at all above grade M&R city gate stations at custody transfer, from paragraph (q) of this section.

Count = Total number of meter runs at all above grade M&R city gate stations at custody transfer.

(s) *Offshore petroleum and natural gas production facilities.* Report CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304.

(1) Offshore production facilities under BOEMRE jurisdiction shall report the same annual emissions as calculated and reported by BOEMRE in data collection and emissions estimation study published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication year, report the most recent BOEMRE reported emissions data published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS). Adjust emissions based on the operating time for the facility relative to the operating time in the most recent BOEMRE published study.

(ii) [Reserved]

(2) Offshore production facilities that are not under BOEMRE jurisdiction shall use monitoring methods and calculation methodologies published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication, report the most recent reported emissions data with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

(ii) [Reserved]

(3) If BOEMRE discontinues or delays their data collection effort by more than 4 years, then offshore reporters shall once in every 4 years use the most recent BOEMRE data collection and emissions estimation methods to report emission from the facility sources.

(4) For either first or subsequent year reporting, offshore facilities either within or outside of BOEMRE jurisdiction that were not covered in the previous BOEMRE data collection cycle shall use the most recent BOEMRE data collection and emissions estimation methods published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS) to report emissions.

(t) *Volumetric emissions.* Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(1) or (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions by converting actual temperature and pressure of natural gas emissions to standard temperature and pressure of natural gas using Equation W–33 of this section.

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s} \quad \text{(Eq. W-33)}$$

Where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a,n}$ = Natural gas volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (psia).

P_a = Absolute pressure at actual conditions (psia).

(2) Calculate GHG volumetric emissions at standard conditions by converting actual temperature and pressure of GHG emissions to standard temperature and pressure using Equation W–34 of this section.

$$E_{s,i} = \frac{E_{a,i} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s} \quad \text{(Eq. W-34)}$$

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a,i}$ = GHG i volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (psia).

P_a = Absolute pressure at actual conditions (psia).

(u) *GHG volumetric emissions.* Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation W–35 of this section.

$$E_{s,i} = E_{s,n} * M_i \quad \text{(Eq. W-35)}$$

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions in cubic feet.

$E_{s,n}$ = Natural gas volumetric emissions at standard conditions in cubic feet.

M_i = Mole fraction of GHG i in the natural gas.

(2) For Equation W–35 of this section, the mole fraction, M_i, shall be the annual average mole fraction for each facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

(i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use your most recent gas composition based on available sample analysis of the field.

(ii) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in § 98.234(b).

(iii) GHG mole fraction in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(iv) GHG mole fraction in natural gas stored in underground natural gas storage facilities.

(v) GHG mole fraction in natural gas stored in LNG storage facilities.

(vi) GHG mole fraction in natural gas stored in LNG import and export facilities.

(vii) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.

(v) *GHG mass emissions.* Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions by converting the GHG volumetric emissions into mass emissions using Equation W–36 of this section.

$$Mass_{s,i} = E_{s,i} * \rho_i * GWP * 10^{-3} \quad \text{(Eq. W-36)}$$

Where:

$Mass_{s,i}$ = GHG i (either CH_4 or CO_2) mass emissions at standard conditions in metric tons CO_2e.

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

ρ_i = Density of GHG i. Use 0.0538 kg/ft³ for CO_2 and N_2O, and 0.0196 kg/ft³ for CH_4 at 68°F and 14.7 psia or 0.0530 kg/ft³ for CO_2 and N_2O, and 0.0193 kg/ft³ for CH_4 at 60°F and 14.7 psia.

GWP = Global warming potential, 1 for CO_2, 21 for CH_4, and 310 for N_2O.

(w) *EOR injection pump blowdown.* Calculate CO_2 pump blowdown emissions as follows:

(1) Calculate the total volume in cubic feet (including pipelines, manifolds and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns per calendar year.

(3) Calculate the total annual venting emissions using Equation W–37 of this section:

$$Mass_{c,i} = N * V_v * R_c * GHG_i * 10^{-3} \quad \text{(Eq. W-37)}$$

Where:

$Mass_{c,i}$ = Annual EOR injection gas venting emissions in metric tons at critical conditions "c" from blowdowns.

N = Number of blowdowns for the equipment in the calendar year.

V_v = Total volume in cubic feet of blowdown equipment chambers (including pipelines, manifolds and vessels) between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/ft³. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice to determine density of super critical EOR injection gas.

GHG_i = Mass fraction of GHG_i in critical phase injection gas.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(x) EOR hydrocarbon liquids dissolved CO_2. Calculate dissolved CO_2 in hydrocarbon liquids produced through EOR operations as follows:

(1) Determine the amount of CO_2 retained in hydrocarbon liquids after flashing in tankage at STP conditions. Annual samples must be taken according to methods set forth in § 98.234(b) to determine retention of CO_2 in hydrocarbon liquids immediately downstream of the storage tank. Use the annual analysis for the calendar year.

(2) Estimate emissions using Equation W–38 of this section.

$$Mass_{s,CO2} = S_{hl} * V_{hl} \quad \text{(Eq. W-38)}$$

Where:

$Mass_{s,CO2}$ = Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids produced through EOR operations beyond tankage, in metric tons.

S_{hl} = Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.

V_{hl} = Total volume of hydrocarbon liquids produced at the EOR operations in barrels in the calendar year.

(y) [Reserved]

(z) *Onshore petroleum and natural gas production and natural gas distribution combustion emissions.* Calculate CO_2 CH_4 and N_2O combustion-related emissions from stationary or portable equipment as follows:

(1) If the fuel combusted in the stationary or portable equipment is listed in Table C–1 of subpart C of this part, or is a blend of fuels listed in Table C–1, use the Tier 1 methodology described in subpart C of this part (General Stationary Fuel Combustion Sources). If the fuel combusted is natural gas and is pipeline quality and has a minimum high heat value of 950 Btu per standard cubic foot, then the natural gas emission factor and high heat values listed in Tables C–1 and C–2 of this part may be used.

(2) For fuel combustion units that combust field gas or process vent gas, or any blend of field gas or process vent gas and fuels listed in Table C–1 of subpart C of this part, calculate combustion emissions as follows:

(i) If you have a continuous flow meter on the combustion unit, you must use the measured flow volumes to calculate the total flow of gas to the unit. If you do not have a permanent flow meter on the combustion unit, you may install a permanent flow meter on the combustion unit, or use company records or engineering calculations based on best available data on heat duty or horsepower to estimate volumetric unit gas flow.

(ii) If you have a continuous gas composition analyzer on fuel to the combustion unit, you must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If you do not have a continuous gas composition analyzer on gas to the combustion unit, you must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit as specified in paragraph (u)(2)(i) of this section.

(iii) Calculate GHG volumetric emissions at actual conditions using Equations W–39 of this section.

$$E_{a,CO2} = \sum_j V_a * Y_j * R_j \quad \text{(Eq. W-39)}$$

Where:

E_{a,CO_2} = Contribution of annual emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

V_a = Volume of gas sent to combustion unit in cubic feet, during the year.

Y_j = Concentration of gas hydrocarbon constituents *j* (such as methane, ethane, propane, butane, and pentanes plus).

R_j = Number of carbon atoms in the gas hydrocarbon constituent *j;* 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions. You must report the type and number of each external fuel combustion unit.

(4) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both combustion-related CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(6) Calculate N_2O mass emissions using Equation W–40 of this section.

$$N_2O = (1 \times 10^3) \times Fuel \times HHV \times EF \quad \text{(Eq. W-40)}$$

Where:

N_2O = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = High heat value of the fuel from paragraphs (z)(8)(i), (z)(8)(ii) or (z)(8)(iii) of this section (units must be consistent with Fuel).

EF = Use 1.0×10^{-4} kg N_2O/mmBtu.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(i) For fuels listed in Table C–1 of subpart C of this part, use the provided default HHV in the table.

(ii) For field gas or process vent gas, use 1.235×10^{-3} mmBtu/scf for HHV.

(iii) For fuels not listed in Table C–1 of subpart C of this part and not field gas or process vent gas, you must use the methodology set forth in the Tier 2 methodology described in subpart C of this part to determine HHV.

§ 98.234 Monitoring and QA/QC requirements.

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable as specified in this section. Offshore petroleum and natural gas production facilities shall adhere to the monitoring and QA/QC requirements as set forth in 30 CFR 250.

(a) You must use any of the methods described as follows in this paragraph to conduct leak detection(s) of equipment leaks and through-valve leakage from all source types listed in § 98.233(k), (o), (p) and (q) that occur during a calendar year, except as provided in paragraph (a)(4) of this section.

(1) *Optical gas imaging instrument.* Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, § 60.18(i)(1) and (2) of the *Alternative work practice for monitoring equipment leaks.* Any emissions detected by the optical gas imaging instrument is a leak unless screened with Method 21 (40 CFR part 60, appendix A–7) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(2) *Method 21.* Use the equipment leak detection methods in 40 CFR part 60, appendix A–7, Method 21. If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. Owners or operators must use alternative leak detection devices as described in paragraph(a)(1) of this section to monitor inaccessible equipment leaks or vented emissions.

(3) *Infrared laser beam illuminated instrument.* Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with Method 21 monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(4) *Optical gas imaging instrument.* An optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(5) *Acoustic leak detection device.* Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, you must use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, you must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters.

(b) You must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in § 98.233 according to the procedures in § 98.3(i) and the procedures in paragraph (b) of this section. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures such that it is safe to handle and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed for measurement.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in § 98.233(t).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(u) and (v).

(d) Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, including positioning the instrument for complete capture of the equipment leak without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(u) and (v).