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Via Federal Express

May 24, 2012

Jeff Robinson (6PD-R)
U.S. Environmental Protection Agency
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

SUBJECT: GHG PSD PERMIT APPLICATION
DCP MIDSTREAM, LP
HARDIN COUNTY NGL FRACTIONATION PLANT

Dear Mr. Robinson,

DCP Midstream, LP ("DCP") is proposing to construct a new natural gas liquids ("NGL") fractionation plant in Hardin County, Texas. The proposed Greenhouse Gas ("GHG") emissions from the plant will exceed the Prevention of Significant Deterioration ("PSD") major source threshold based on emission estimates; therefore, the plant will be considered a major stationary source with respect to GHG emissions. Because the United States Environmental Protection Agency ("USEPA") is currently the permitting authority for GHG major stationary sources in the State of Texas, DCP is required to submit a GHG PSD permit application to USEPA Region 6 to authorize construction of the proposed facility.

On behalf of DCP, Spirit Environmental, LLC ("Spirit") is submitting the GHG PSD permit application in searchable Portable Document Format ("PDF") on the enclosed compact disc. The application includes a process description, emission estimates, regulatory applicability review, Best Available Control Technology analysis, and supporting information in compliance with Title 40 Code of Federal Regulations Part 52 and Part 98.

If you need any additional information please contact Lynn Ward at (903) 694-4114 or me at (281) 664-2820.

FOR SPIRIT ENVIRONMENTAL, LLC

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GHG PSD PERMIT APPLICATION

DCP Midstream, LP
Hardin County NGL Fractionation Plant

Prepared for:

DCP Midstream, LP
Houston, Texas

FOR SPIRIT ENVIRONMENTAL, LLC

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List of Figures

List of Tables

1.0 INTRODUCTION

DCP Midstream, LP ("DCP") is submitting this air permit application to the United States Environmental Protection Agency ("USEPA") Region 6, proposing to construct a Natural Gas Liquids ("NGL") Fractionation facility. The facility will be located in Hardin County, Texas approximately 1.5 miles Northeast of Hull, Texas. The site will be referred to as the "Hardin County NGL Fractionation Plant." This document represents a request by DCP for USEPA Region 6 to issue a Greenhouse Gas ("GHG") Prevention of Significant Deterioration ("PSD") air permit to construct the proposed facility.

The Hardin County NGL Fractionation Plant will be a new grassroots site. The site is not contiguous with any other DCP property. The facility has the potential to emit more than 100,000 tons per year ("tpy") of carbon dioxide equivalents ("CO_2e"); therefore, the facility will be considered a new major stationary source of GHGs. Because the facility will be a new major stationary source, it requires a GHG PSD air construction permit from USEPA Region 6. The facility also has the potential to emit more than 250 tpy of carbon monoxide ("CO") and nitrogen oxides ("NO_X"); therefore, the facility will be considered a new major stationary source for CO and NO_X. Because the facility will be a new major stationary source for CO and NO_X, all other pollutants must be assessed against PSD significant emission levels to determine if the potential emission rates will trigger PSD review. The facility has the potential to emit more than 40 tpy of volatile organic compounds ("VOC"), more than 40 tpy of sulfur dioxide ("SO_2"), more than 15 tpy of particulate matter equal to or less than 10 microns in diameter ("PM_{10}"), and more than 10 tpy of particulate matter equal to or less than 2.5 microns in diameter ("$PM_{2.5}$"); therefore, these pollutants exceed the PSD significant emission levels and will require PSD review. Because the facility will also be considered a new major stationary source for criteria pollutants, a PSD air construction permit application is required to be submitted to the Texas Commission on Environmental Quality ("TCEQ"). Specific PSD applicability to the proposed facility is discussed in Section 4 of this application. A copy of the TCEQ criteria pollutant PSD permit application will be provided to USEPA Region 6.

1.1 APPLICATION OVERVIEW

The purpose of this document is to provide all technical and administrative information necessary for the USEPA Region 6 to issue a GHG PSD air construction permit to DCP for the construction of the proposed Hardin County NGL Fractionation Plant. The facility will consist of three process trains with a capacity of 75,000 barrels per day ("bpd") each of Y-grade NGL feedstock. The facility will separate Y-grade NGL feedstock into ethane, propane, butane, isobutane, and gasoline using a fractionation process. The feedstock will be supplied to the facility via a pipeline. The separated NGL products will be transported to DCP customers via pipeline.

The remainder of this application includes the information necessary to evaluate the GHG air emissions associated with the proposed Hardin County NGL Fractionation Plant. Section 1.2 addresses the facility location, Section 1.3 provides a summary of required permit forms and tables, and Section 1.4 provides information regarding correspondence with the applicant. Section 2 contains a Process Description, and Section 3 provides a GHG Emissions Summary for the proposed Hardin County NGL Fractionation Plant. Section 4 and Section 5 address Regulatory Applicability and Best Available Control Technology ("BACT") associated with GHG emissions, respectively. Section 6 contains attachments to the application, including permit forms and tables (Attachment A), detailed GHG emission estimates (Attachment B), support documentation (Attachment C), and supporting BACT information (Attachment D).

1.2 SITE AND UNIT LOCATION

Figure 1-1 provides the location of the proposed site relative to the immediate surrounding area. This figure illustrates the property boundary of the proposed Hardin County NGL Fractionation Plant and an outline of the process area within the proposed property boundary.

N

0 2000 4000
SCALE IN FEET

Image Source: Google Earth - 11/28/2011

Figure 1-1

DCP Midstream
Hardin County Plant Site
Hardin County, Texas
Area Map

Date: 05-22-2012	File: HardinCoPlant_AreaMap

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1.3 PERMIT FORMS AND INFORMATION

DCP understands that the USEPA Region 6 does not currently have forms for PSD air permit applications and has requested that the permit applicant use the appropriate TCEQ forms. Therefore, DCP has included the appropriate TCEQ permit forms and tables in this application. Section 6, Attachment A includes Form PI-1 Permit Application, Table 1(a) Emission Point Summary, Table 4 Combustion Units, Table 6 Boilers and Heaters, Table 7(a) Vertical Fixed Roof Storage Tank Summary, Table 7(b) Horizontal Fixed Roof Storage Tank Summary, Table 29 Reciprocating Engines, and Table 31 Combustion Turbines.

1.4 CORRESPONDENCE WITH APPLICANT

Please direct all email/mail correspondence and telephone requests regarding review of the permit application to:

Ms. Lynn Ward
Senior Environmental Specialist
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662 South Shelby
Carthage, TX 75633
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(903) 694-4114

Please send a copy of all email/mail correspondence to:

Mr. Brad Herrin
Spirit Environmental, LLC
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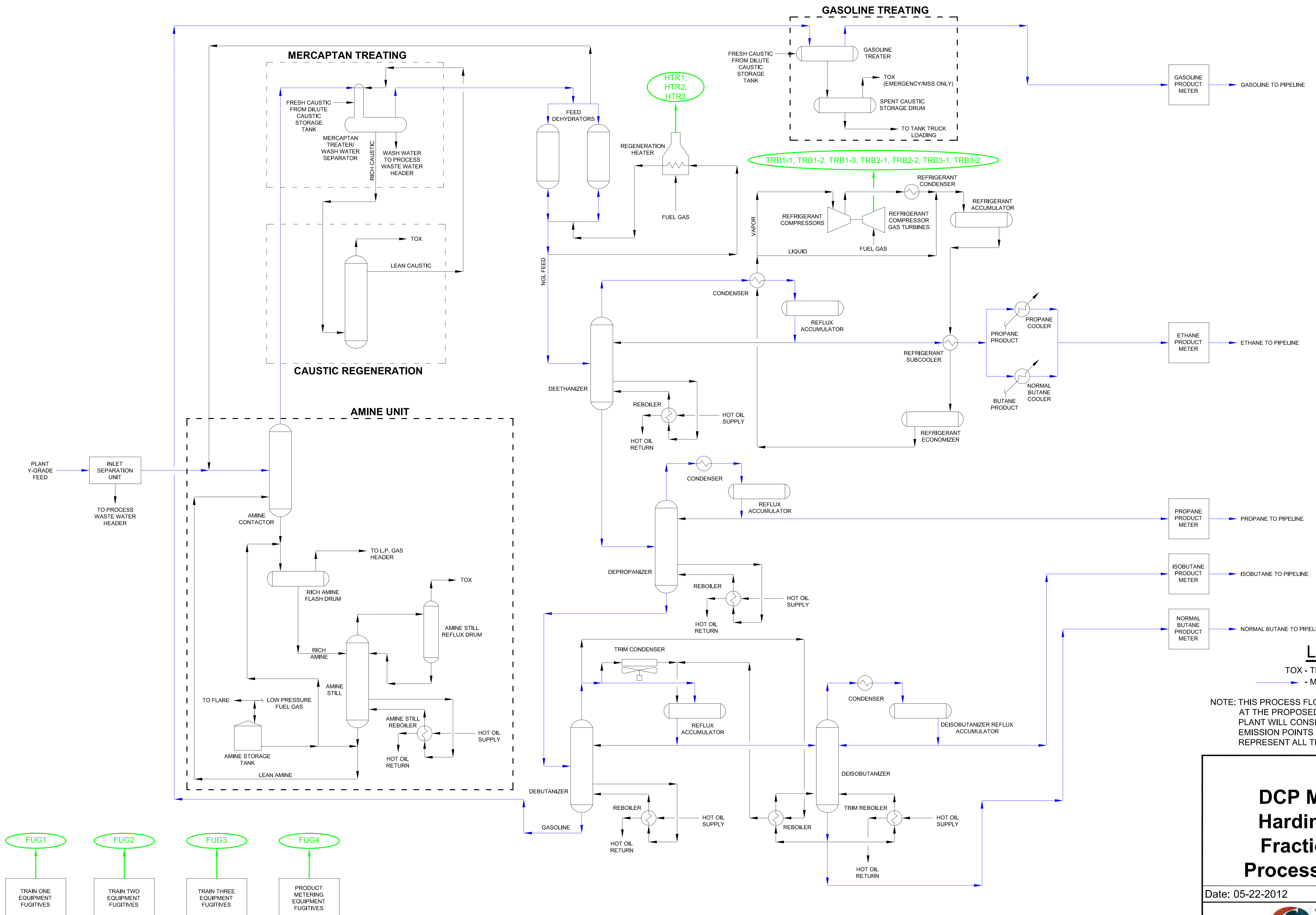
2.0 PROCESS DESCRIPTION

DCP is seeking to authorize the construction of a three-train NGL fractionation plant to separate a Y-grade NGL feed into liquid products – ethane, propane, butane, isobutane, and natural gasoline. The facility will be designed with a capacity of 75,000 bpd per train and includes amine treating, mercaptan treating, molecular sieve dehydration, hot oil as the primary heat source, refrigerant propane and wet surface air condensers ("WSAC") for cooling, a thermal oxidizer ("TO") for control of waste gas streams, and an emergency flare. Compression for the propane refrigeration will be accomplished using compressors powered by natural gas-fired turbines. The hot oil for the process is heated using a combination of natural gas-fired heaters and waste heat from the exhaust of the natural gas-fired turbines. Heat exchangers will be incorporated throughout the process to take advantage of heating and cooling efficiencies. The feed to the NGL facility will be supplied from existing and proposed pipelines and underground storage. The product sales will also consist of pipeline delivery or delivery to underground storage. Figures 2-1 and 2-2 provide process flow diagrams for the Hardin County NGL Fractionation Plant.



LEGEND

TOX - THERMAL OXIDIZER

- MAIN PROCESS LINE

NOTE: THIS PROCESS FLOW DIAGRAM REPRESENTS ONE TRAIN AT THE PROPOSED NGL FRACTIONATION PLANT. THE PLANT WILL CONSIST OF THREE SIMILAR TRAINS. EMISSION POINTS INCLUDED ON THIS DIAGRAM REPRESENT ALL THREE TRAINS.

Figure 2-1

DCP Midstream, LP
Hardin County NGL Fractionation Plant
Process Flow Diagram

Date: 05-22-2012	File: HardinCoPlant_PFD

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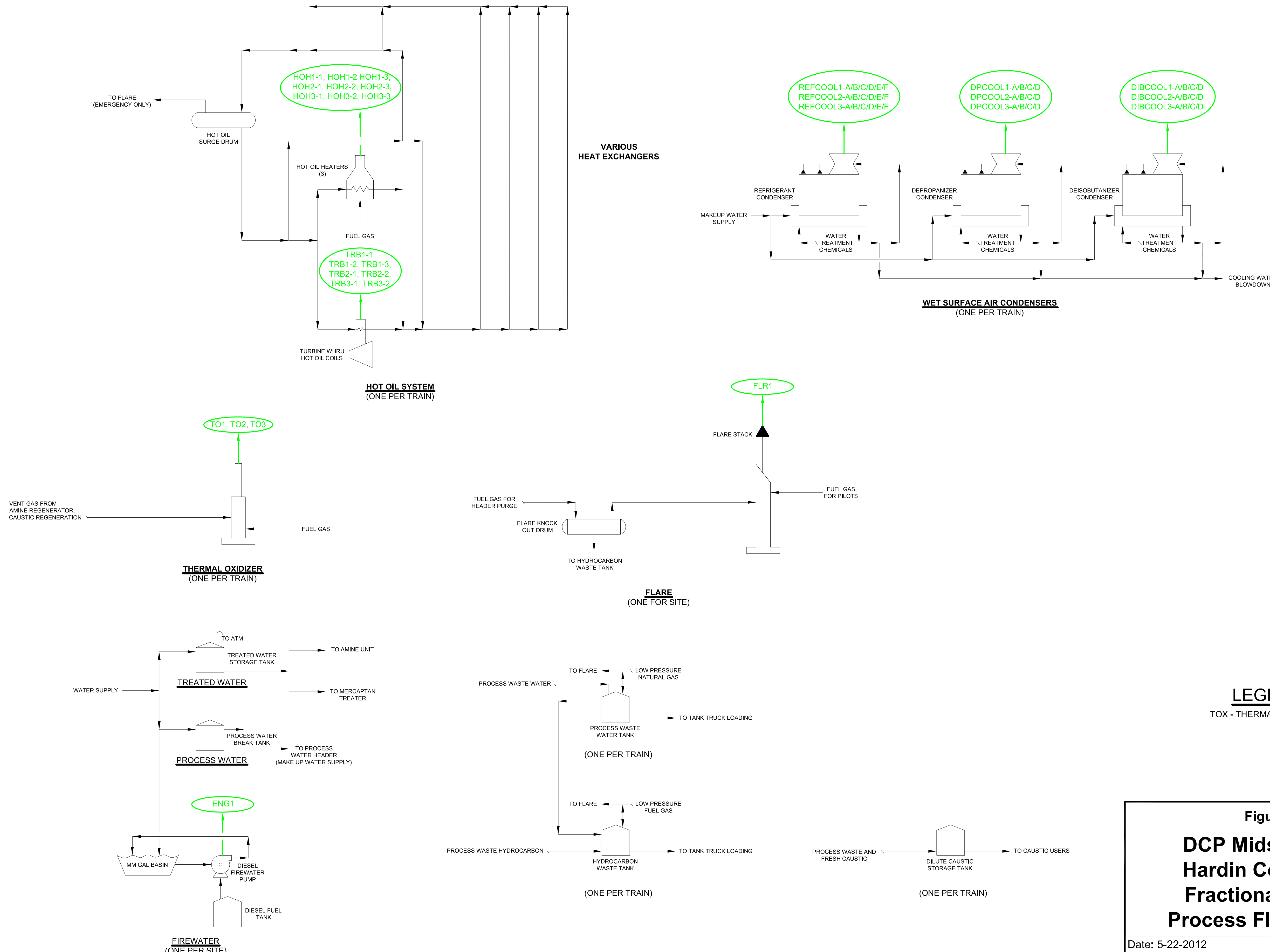

LEGEND

TOX - THERMAL OXIDIZER

Figure 2-2

DCP Midstream, LP
Hardin County NGL Fractionation Plant
Process Flow Diagram

Date: 5-22-2012	File: HardinCoPlant_PFD

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2.1 INLET SEPARATION/AMINE TREATING

The Y-grade NGL feed stock will enter the facility through the inlet separation unit prior to treating for carbon dioxide ("CO_2") removal in the liquid-to-liquid Amine Unit. The inlet separation consists of a series of filters, separators, and metering. Particulates and free water will be removed in the inlet section.

After metering, the feed enters the Amine Unit, where the feed is treated to remove CO_2 by the introduction of an amine solvent. The Y-grade NGL enters the amine contactor, where lean amine is introduced in a counter-current flow. The CO_2 will have a greater affinity for the amine solvent and will attach to the amine molecule, becoming "rich" amine. From the amine contactor, the rich amine is passed through a flash drum and filters to remove any entrained contaminants. Light hydrocarbons that flash enter the low pressure fuel gas system. The rich amine is then warmed using a heat exchanger prior to entering the amine still, where the amine is regenerated using heat to break the molecular bonds between the CO_2 and the rich amine. The amine that exits the bottom of the amine still is now "lean", as the CO_2 has been removed.

Heat for the amine still is provided by a heat exchanger using hot oil from the plant hot oil system. The overheads from the amine still are routed through a cooler to the amine regenerator reflux drum, where condensed liquid consisting of mostly water is collected and pumped back to the amine still. The overhead gas stream, consisting of mostly CO_2 with some sulfur compounds and hydrocarbons, is routed to the TO for destruction of the sulfur compounds and hydrocarbons.

The lean amine from the bottom of the amine still is cooled by routing back through the lean/rich amine heat exchanger and an additional cooler to reach the desired temperature to be reused in the amine contactor. The cooled lean amine is pumped back to the amine contactor, where the process of CO_2 removal from the Y-grade NGL begins again. An amine solvent storage tank provides fresh amine to the process to replace any amine lost through the regeneration process. Following removal of the CO_2, the NGL feed is routed to the Mercaptan/Gasoline Treating/Caustic Regeneration section of the process.

2.2 MERCAPTAN/GASOLINE TREATING/CAUSTIC REGENERATION

The NGL leaving the Amine Unit is introduced into the top of the mercaptan treater and mixed with a "lean" caustic from the caustic regeneration section. The light mercaptans, residual H_2S, and CO_2 are extracted into the caustic, creating a "rich" caustic. The rich caustic and the treated NGL are separated in the mercaptan treater. The treated NGL leaving the mercaptan treater is routed to the wash water separator, where any residual caustic is removed using fresh process water. Wash water containing caustic extracted from the NGL is routed to the process waste water tank. Treated NGL is routed to the dehydration section of the process.

Rich caustic from the bottom of the mercaptan treater flows to the caustic regeneration system. The off-gas from the top of the caustic regeneration system is routed to the TO.

The gasoline product stream from the Debutanizer bottoms of the process is also treated with caustic for removal of heavier sulfur compounds. The gasoline product is routed to the metering section of the process for shipment off-site via pipeline.

Spent caustic is drained from the gasoline treater to the spent caustic storage drum periodically and is loaded out to tank trucks for disposal off-site, as necessary. Fresh caustic is stored in the dilute caustic storage tank and supplied to the merceptan treater and the gasoline treater periodically to maintain the proper caustic concentration.

2.3 DEHYDRATION UNIT

From mercaptan treating, the NGL will be routed through a two-bed molecular sieve dehydration unit to remove any entrained water. Each molecular sieve tower is packed with a desiccant that removes water by a process called adsorption. During adsorption, water molecules are adsorbed to the desiccant due to the greater attraction of the water molecule. When the bed is saturated, hot dry gas is passed through the bed in order to vaporize the water and regenerate the molecular sieve. The hot dry gas needed to regenerate the bed is a slip stream of the dry Y-grade feed that is vaporized by a natural gas-fired heater before it enters the dehydrator. When the slip stream enters the molecular sieve tower, the water is desorbed from the sieve bed. The vaporized NGL, which now contains water vapor, is condensed and sent to the inlet of the amine contactor in the amine treating section of the process, where it combines with the NGL feed. The excess water in the feed is removed by the amine solvent.

Under normal operating conditions, one of the two dehydrator towers will be in adsorption while the other is in regeneration. After the NGL leaves the molecular sieve tower and the water has been removed, the NGL is sent to the Fractionation section of the process for separation.

2.4 FRACTIONATION

The NGL feed is sent from the dehydrators to the Deethanizer column. The Deethanizer Condenser uses propane refrigerant to cool the overhead vapors. The condensed liquid is collected in the Deethanizer Reflux Accumulator. A portion of the liquid is sent back to the Deethanizer as reflux with the remaining exiting the reflux accumulator as the ethane product. The ethane product is used to cool propane and butane in the respective product coolers, and propane refrigerant in the refrigerant subcooler before the ethane is sent through the metering section of the process and out to the ethane pipeline.

The Deethanizer has two side Reboiler process-to-process heat exchangers (not shown on Figure 2-1 to simplify diagram). The upper side is heat integrated with Deethanizer bottoms. The lower side is integrated with the Depropanizer bottoms. The Deethanizer Reboiler uses hot oil from the hot oil system as a heat source. The bottoms product from the Deethanizer is sent as feed to the Depropanizer.

The Depropanizer uses a WSAC to condense overhead vapors. The condensed liquid is collected in the Depropanizer Reflux Accumulator. A portion of the liquid is sent back to the Depropanizer as reflux, and the remainder exits the reflux accumulator as propane product. This propane product is sent through the metering section of the process and out to the propane pipeline. The Depropanizer Reboiler uses hot oil from the hot oil system as a heat source. The bottoms product is sent as feed to the Debutanizer.

Debutanizer overhead vapors are fully condensed in the Deisobutanizer Reboiler, which provides energy to the Deisobutanizer. During times of abnormal operation, such as startup/shutdown, when the Reboiler duty requirements are low, trim cooling, which can occupy up to 50% of the normal duty, can be provided by the Debutanizer trim condenser (fin fan cooler). The condensed liquid is collected in the Debutanizer Reflux Accumulator. A portion of the liquid is sent back to the Debutanizer as reflux, and the remainder is sent as feed to the Deisobutanizer. The Debutanizer Reboiler uses hot oil from the hot oil system as a heat source.

Feed from the Debutanizer Reflux Accumulator enters the Deisobutanizer for separation into n-butane and isobutane. The Deisobutanizer utilizes a WSAC to condense the overhead vapors. The condensed liquid is collected in the Deisobutanizer Reflux Accumulator. A portion of the liquid is sent back to the Deisobutanizer as reflux with the remainder exiting the reflux accumulator as the isobutane product. The isobutane product is sent through the metering section of the process and out to the isobutane pipeline.

The Deisobutanizer also includes two reboilers operating in parallel. The trim reboiler uses hot oil from the hot oil system as a heat source. The Deisobutanizer Reboiler is heat integrated with the Debutanizer overheads. The bottoms product from the Deisobutanizer is cooled in the normal butane product cooler using energy from the ethane product stream. The normal butane product is sent through the metering section of the process and out to the normal butane pipeline.

2.5 PROPANE REFRIGERATION

The Propane Refrigeration System is a closed-loop that supplies cold propane refrigerant to the Deethanizer condenser. Propane refrigerant is compressed by two compressors powered by natural gas-fired turbines that combust high pressure natural gas ("HPNG"). The refrigeration compressor inlet suction pressure will cascade to reset the speed of the natural gas turbines to minimize natural gas usage. Heat from the natural gas turbine exhaust is recovered by using the exhaust gas to heat a portion of the hot oil for the plant hot oil system in the waste heat recovery unit ("WHRU") hot oil coils.

Propane from the compressors is condensed, using a WSAC to reduce the amount of compression required for refrigeration. The condensed propane flows to the refrigerant accumulator and is further cooled by the refrigerant subcooler. The refrigerant subcooler is a process-to-process heat exchanger that uses energy from the ethane product stream, thereby reducing compression requirements. The propane is then flashed and sent to the propane refrigerant economizer. Liquid propane from the economizer is used in the Deethanizer condenser to condense ethane from the top of the Deethanizer tower. The resulting propane vapor from the Deethanizer condenser is recycled back to the refrigerant compressors and any liquid to the refrigerant accumulator.

2.6 WET SURFACE AIR CONDENSERS

WSAC are used to condense propane refrigerant, propane, and isobutane. These condensers operate by having warm process fluids flow through tubes which are sprayed with water. Air is drawn down across the tubes by a fan, creating a cooling effect by evaporating the water. The water not evaporated is collected in a basin and pumped back to the top of the tower to begin the process again. The evaporated water and air are discharged from the top of the condenser by a fan to the atmosphere.

These devices operate under the same principle as a water cooling tower; however, by using more direct cooling of the process fluids, they can be cooled to lower temperatures. The reduction in condensing temperatures reduces the pressures needed for condensing, thereby reducing emissions from combustion devices due to lower requirements for Reboiler and compressor duties.

2.7 HOT OIL SYSTEM

As shown in Figure 2-2, the hot oil system is a closed-loop system that supplies hot oil to various heat exchangers. The Hot Oil Surge Drum is a fuel gas-blanketed vessel that collects all the hot oil returns. The hot oil pumps are used to pump hot oil to the hot oil heaters and refrigerant compressor turbine WHRUs. The hot oil heaters are natural gas-fired, and the natural gas-fired turbines that power the refrigerant compressors are equipped with WHRUs. Heat exchangers for the Deethanizer Reboiler, Depropanizer Reboiler, Debutanizer Reboiler, Deisobutanizer Trim Reboiler, Amine Regenerator Reboiler and the Caustic Heater all utilize hot oil as the heat source.

2.8 FUEL GAS SYSTEM

Sweet natural gas is supplied to the facility for the gas-fired equipment. The natural gas coming into the plant is sent to the fuel gas knock out ("KO") drum. The natural gas from the KO drum flows into a high pressure fuel gas header.

2.9 FLARE

The Flare System collects relief valve discharges, other emergency vents, and maintenance, startup, and shutdown ("MSS") vents. Vapors are sent to the flare and liquids are pumped via the flare KO drum to the hydrocarbon waste tank. The flare is equipped with a natural gas-fired continuous pilot, a continuous natural gas purge on the flare header, and a flare stack blower ensuring a smokeless design. The presence of the pilot is continuously monitored by a thermocouple or the equivalent. The flare is designed as an emergency flare. Emissions associated with MSS will also be routed to the flare.

2.10 THERMAL OXIDIZER

Each train will be equipped with a TO rated at 8.25 million British thermal units per hour ("MMBtu/hr") that will be used to combust two waste gas streams from the process during normal operation. The first waste stream is the acid gas from the amine regeneration system. This stream is comprised of primarily CO_2 with some sulfur species and VOCs. The second waste stream is the caustic regenerator off-gas from the mercaptan caustic treating system containing various mercaptans, sulfur compounds, hydrocarbons, and natural gas. The TO will operate with a destruction efficiency of 99.9% for VOC and H_2S. The combustion chamber will maintain a temperature of 1,400 degrees Fahrenheit and a residence time of 0.5 seconds or greater to ensure a 99.9% destruction efficiency. The top of the exhaust stack is proposed to be 100 feet above ground level and 5 feet in diameter.

2.11 PRODUCT DELIVERY

All products from the Hardin County NGL Fractionation Plant will be delivered off-site via pipeline. Each product will go through a filtering and metering skid prior to entering the product pipeline. Each product will be quality checked prior to entering the respective metering skid and will be sent to an off-site Y-grade storage cavern via pipeline if determined not to be within specifications.

3.0 EMISSION RATE ESTIMATES

This section of the application provides detailed GHG emission rate estimates for each source associated with the Hardin County NGL Fractionation Plant. Sections 3.3 through 3.12 contain detailed normal operation emission rate estimates, while emission rates due to MSS activities are provided in section 3.13. Figures 2-1 and 2-2 in Section 2 are process flow diagrams that illustrate the location within the process of each emission point. Figure 3-1 is a facility plot plan that provides the proposed physical location of each emission point within the Hardin County NGL Fractionation Plant. Please note this application addresses emission rates of CO_2, methane (“CH_4”), and nitrous oxide (“N_2O”) only. Some sources, such as the WSAC, do not emit GHGs and are, therefore, not included in these emission rate estimates. Emission rates of all GHG pollutants from each source for both normal and MSS operations are summarized at the end of each subsection. Detailed GHG emission estimate calculations are provided in Section 6, Attachment B. Emission rates of other regulated NSR pollutants are addressed in the PSD permit application submitted to the TCEQ. A copy of the TCEQ PSD permit application will be submitted to USEPA Region 6.

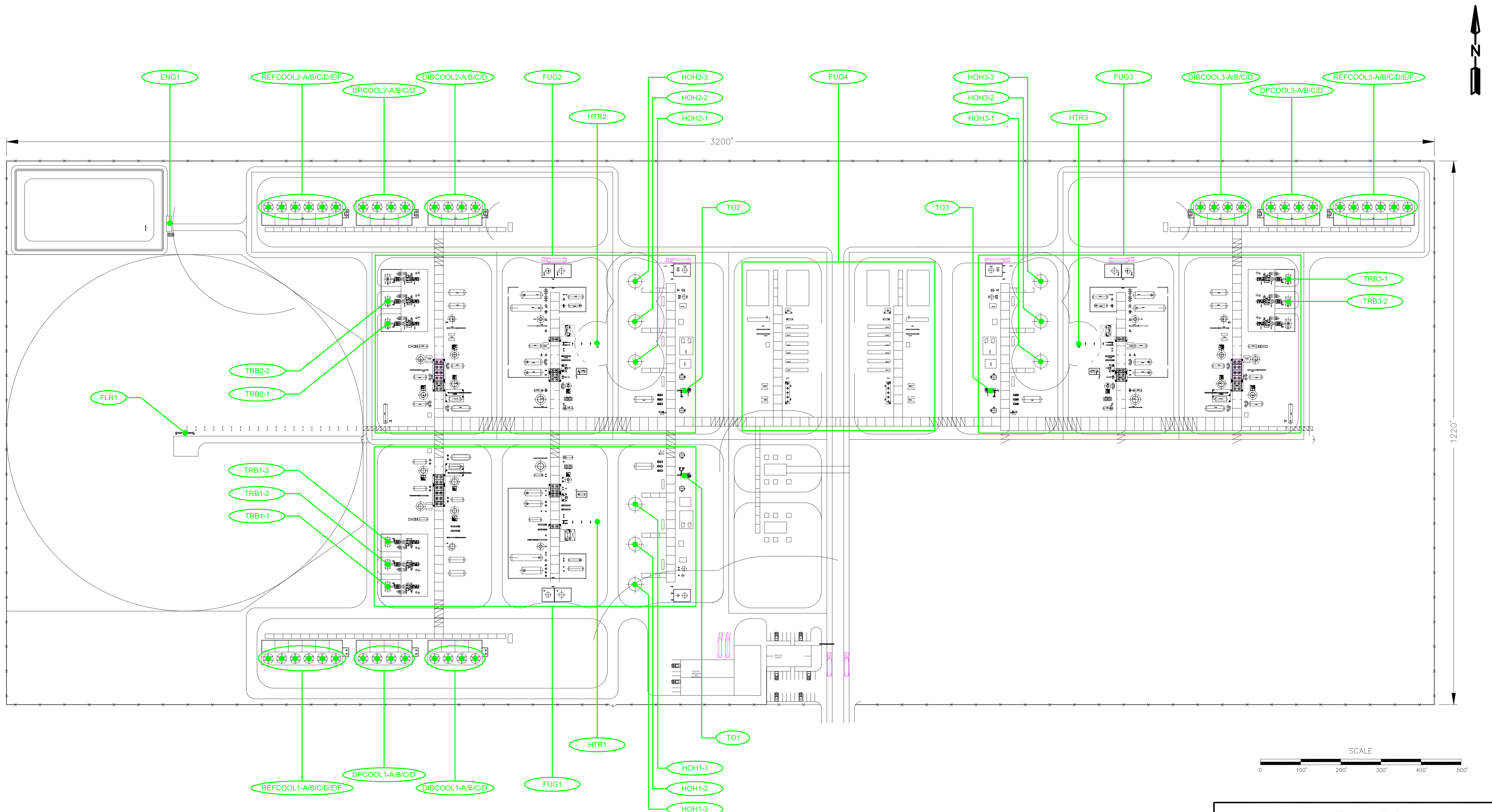

Figure 3-1

DCP Midstream, LP Hardin County NGL Fractionation Plant Plot Plan

Date: 05-7-2012	File: HardinCoPlant_PLotPLan

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3.1 COMBUSTION EMISSION FACTOR SELECTION

3.1.1 COMBUSTION OF NATURAL GAS

Two sets of published emission factors are available for use in estimating the GHG emission rates from combustion sources fired using natural gas: the set published in 40 Code of Federal Regulations ("CFR") Part 98, Subpart C, Tables C-1 and C-2 [the Mandatory Reporting Rule ("MRR")] and the set published in AP-42 (Chapter 1 for the heaters, flare, and TO; Chapter 3 for the turbines and engine). To maintain consistency across all reporting and recordkeeping requirements and programs, the combustion emission rates are estimated using factors from the MRR only. The MRR emission factors for natural gas combustion use a default high heating value ("HHV") of 1,028 British thermal units per standard cubic foot ("Btu/scf").

The emission factors for natural gas are converted from kilograms per million British thermal units ("kg/MMBtu") to pounds per million standard cubic foot ("lb/MMscf") as follows (using CO_2 as an example):

$$\left(\frac{53.02\ \text{kg } CO_2}{\text{MMBtu}}\right) \times \left(\frac{2.2046\ \text{lb } CO_2}{\text{kg } CO_2}\right) \times \left(\frac{1\ \text{MMBtu}}{10^6\ \text{Btu}}\right) \times \left(\frac{1{,}028\ \text{Btu}}{\text{scf}}\right) \times \left(\frac{10^6\ \text{scf}}{1\ \text{MMscf}}\right) = 120{,}161\ \frac{\text{lb } CO_2}{\text{MMscf}}$$

3.1.2 COMBUSTION OF WASTE GAS

GHG emissions for the combustion of waste gas are estimated using the methodology in 40 CFR Part 98, Subpart W. CO_2 emissions are estimated assuming all carbon in the waste gas streams is converted into CO_2 during combustion. N_2O emissions are estimated using the emission factor 1.0×10^{-4} kg/MMBtu and a waste gas heating value of 1.235×10^{-3} MMBtu/scf from Equation W-40 in 40 CFR Part 98, Subpart W.

3.2 CARBON DIOXIDE EQUIVALENT

The CO_2e emission rates for each source are estimated by multiplying the individual GHG emission rate by the appropriate global warming potential ("GWP") as specified in 40 CFR Part 98, Subpart A, Table A-1. Table 3.2-1 presents the GWP of each GHG.

Table 3.2-1
GWP of Selected GHGs

CO_2	CH_4	N_2O
1	21	310

For example, the hourly CO_2e emission rate from one turbine (See Section 3.3) is estimated as follows:

$$\left(\frac{5{,}612.87\ \text{lb CO}_2}{\text{hr}}\right) \times (1) + \left(\frac{0.11\ \text{lb CH}_4}{\text{hr}}\right) \times (21) + \left(\frac{0.01\ \text{lb N}_2\text{O}}{\text{hr}}\right) \times (310) = 5{,}618.28\ \frac{\text{lb}}{\text{hr}}\text{CO}_2\text{e}$$

3.3 REFRIGERATION COMPRESSOR TURBINES

The gas-fired turbines at the Hardin County NGL Fractionation Plant are Solar Saturn T-4700 model gas-fired turbines used to power refrigeration compressors. Each train at the Hardin County NGL Fractionation Plant will utilize two turbines. The Hardin County NGL Fractionation Plant will also have one supplemental turbine supporting all three trains in the event extra compression is required. The turbines are fired using natural gas delivered via pipeline. Combustion of this fuel within the turbines results in GHG emissions. Emission rates of CO_2, CH_4, N_2O, and CO_2e are estimated for each turbine as described in Sections 3.3.1 and 3.3.2 below.

3.3.1 CO_2, CH_4, AND N_2O EMISSION RATE ESTIMATES

The CO_2, CH_4, and N_2O emission factors are based on the MRR, as discussed in Section 3.1. The emission factor for each GHG is presented in Table 3.3-1.

The maximum hourly emission rates ("E_{MAX}") of CO_2, CH_4, and N_2O from the turbines are estimated as follows (using CO_2 as an example):

$$E_{MAX}\left(\frac{lb}{hr}\right) = F \div NG \times HR \times \left(\frac{1\ MMBtu}{10^6\ Btu}\right)$$
$$= \left(\frac{120{,}161\ lb\ CO_2}{MMscf}\right) \times \left(\frac{scf}{918.14\ Btu}\right) \times \left(\frac{42.89\ MMBtu}{hr}\right) \times \left(\frac{1\ MMBtu}{10^6\ Btu}\right)$$
$$= 5{,}612.87\ \frac{lb}{hr}\ CO_2$$

Where F = Emission Factor (lb CO_2/MMscf)
NG = Heating Value of Natural Gas (Btu/scf)
HR = Maximum Turbine Heat Input Rate (MMBtu/hr)

The annual emission rates ("E_{ANN}") are based 8,760 operating hours per year. The emission rates are estimated as follows (using CO_2 as an example):

$$E_{ANN}\ (tpy) = F \div NG \times HR \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lbs}\right)$$
$$= \left(\frac{120{,}161\ lb\ CO_2}{MMscf}\right) \times \left(\frac{scf}{918.14\ Btu}\right) \times \left(\frac{42.89\ MMBtu}{hr}\right) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lbs}\right)$$
$$= 24{,}584.39\ tpy\ CO_2$$

Where F = Emission Factor (lb CO_2/MMscf)
NG = Heating Value of Natural Gas (Btu/scf)
HR = Maximum Turbine Heat Input Rate (MMBtu/hr)

The emission rate of each GHG per turbine is summarized in Table 3.3-1.

Table 3.3-1
Turbine GHG Emission Rates

Pollutant	Emission Factor (lb/MMscf)	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	120,161	5,612.87	24,584.39
CH_4	2.27	0.11	0.46
N_2O	0.23	0.01	0.05

3.3.2 CO_2e EMISSION RATE ESTIMATES

The total CO_2e emission rate for each turbine is estimated by multiplying the speciated GHG emission rates in Table 3.3-1 by the appropriate GWP in Table 3.2-1.

Table 3.3-2 summarizes the CO_2e emission rates for each turbine at the Hardin County NGL Fractionation Plant.

Table 3.3-2
GHG Emission Rates for All Turbines

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
TRB1-1	CO_2e	5,618.28	24,609.55
TRB1-2	CO_2e	5,618.28	24,609.55
TRB1-3	CO_2e	5,618.28	24,609.55
TRB2-1	CO_2e	5,618.28	24,609.55
TRB2-2	CO_2e	5,618.28	24,609.55
TRB3-1	CO_2e	5,618.28	24,609.55
TRB3-2	CO_2e	5,618.28	24,609.55
Total		**39,327.96**	**172,266.85**

3.4 HOT OIL HEATERS

The hot oil system at the Hardin County NGL Fractionation Plant will use three heaters per train to heat an oil medium to deliver heat to the rest of the plant. The hot oil heaters are fired using natural gas delivered via pipeline. Combustion of this fuel within the hot oil heaters results in GHG emissions.

3.4.1 CO_2, CH_4, AND N_2O EMISSION RATE ESTIMATES

The CO_2, CH_4, and N_2O emission factors are from the MRR, as discussed in Section 3.1. The emission factor for each GHG is presented in Table 3.4-1.

The E_{MAX} of CO_2, CH_4, and N_2O from the hot oil heaters are estimated as follows (using CO_2 as an example):

$$E_{MAX}\left(\frac{lb}{hr}\right) = F \div HV \times HR$$
$$= \left(\frac{120{,}161 \text{ lb } CO_2}{MMscf}\right) \times \left(\frac{scf}{918.14 \text{ Btu}}\right) \times \left(\frac{90 \text{ MMBtu}}{hr}\right)$$
$$= 11{,}778.69 \frac{lb}{hr} CO_2$$

Where F = Emission Factor (lb CO_2/MMBtu)
HV = Heating Value of Natural Gas (Btu/scf)
HR = Maximum Heater Firing Rate (MMBtu/hr)

The E_{ANN} of each compound from the hot oil heaters are based 8,760 operating hours per year. The emission rates are estimated as follows (using CO_2 as an example):

$$E_{ANN}\,(tpy) = F \div HV \times HR \times \left(\frac{8{,}760 \text{ hrs}}{yr}\right) \times \left(\frac{1 \text{ ton}}{2{,}000 \text{ lbs}}\right)$$
$$= \left(\frac{120{,}161 \text{ lb } CO_2}{MMscf}\right) \times \left(\frac{scf}{918.14 \text{ Btu}}\right) \times \left(\frac{90 \text{ MMBtu}}{hr}\right) \times \left(\frac{8{,}760 \text{ hrs}}{yr}\right) \times \left(\frac{1 \text{ ton}}{2{,}000 \text{ lbs}}\right)$$
$$= 51{,}590.68 \text{ tpy } CO_2$$

Where F = Emission Factor (lb CO_2/MMscf)
HV = Heating Value of Natural Gas (Btu/scf)
HR = Maximum Heater Firing Rate (MMBtu/hr)

The emission rate of each GHG per hot oil heater is summarized in Table 3.4-1.

Table 3.4-1
Hot Oil Heater GHG Emission Rates

Pollutant	Emission Factor (lb/MMscf)	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	120,161	11,778.69	51,590.68
CH_4	2.27	0.22	0.97
N_2O	0.23	0.02	0.10

3.4.2 CO_2e EMISSION RATE ESTIMATES

The total CO_2e emission rate for each hot oil heater is estimated by multiplying the speciated emission rates in Table 3.4-1 by the appropriate GWP in Table 3.2-1.

Table 3.4-2 summarizes the CO_2e emission rates for each hot oil heater at the Hardin County NGL Fractionation Plant.

Table 3.4-2
GHG Emission Rates for All Hot Oil Heaters

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
HOH1-1	CO_2e	11,789.51	51,642.05
HOH1-2	CO_2e	11,789.51	51,642.05
HOH1-3	CO_2e	11,789.51	51,642.05
HOH2-1	CO_2e	11,789.51	51,642.05
HOH2-2	CO_2e	11,789.51	51,642.05
HOH2-3	CO_2e	11,789.51	51,642.05
HOH3-1	CO_2e	11,789.51	51,642.05
HOH3-2	CO_2e	11,789.51	51,642.05
HOH3-3	CO_2e	11,789.51	51,642.05
Total		**106,105.59**	**464,778.45**

3.5 MOLECULAR SIEVE DEHYDRATOR REGENERATION HEATERS

The system used to dehydrate the inlet feed stock at the Hardin County NGL Fractionation Plant will use one regeneration heater per train to regenerate the molecular sieve dehydrator beds. The regeneration heaters are fired using natural gas delivered via pipeline. Combustion of this fuel within the regeneration heaters results in emissions of GHG.

3.5.1 CO_2, CH_4, AND N_2O EMISSION RATE ESTIMATES

The CO_2, CH_4, and N_2O emission factors are from the MRR, as discussed in Section 3.1. The emission factor for each GHG is presented in Table 3.5-1.

The E_{MAX} of CO_2, CH_4, and N_2O from the regeneration heaters are estimated as follows (using CO_2 as an example):

$$E_{MAX}\left(\frac{lb}{hr}\right) = F \div HV \times HR$$
$$= \left(\frac{120{,}161 \text{ lb } CO_2}{\text{MMscf}}\right) \times \left(\frac{\text{scf}}{918.14 \text{ Btu}}\right) \times \left(\frac{14.7 \text{ MMBtu}}{\text{hr}}\right)$$
$$= 1{,}923.85 \ \frac{lb}{hr} \ CO_2$$

Where F = Emission Factor (lb CO_2/MMBtu)
HV = Heating Value of Natural Gas (Btu/scf)
HR = Maximum Heater Firing Rate (MMBtu/hr)

The E_{ANN} of each compound from the regeneration heaters are based 8,760 operating hours per year. The emission rates are estimated as follows (using CO_2 as an example):

$$E_{ANN}\ (tpy) = F \div HV \times HR \times \left(\frac{8{,}760 \text{ hrs}}{\text{yr}}\right) \times \left(\frac{1 \text{ ton}}{2{,}000 \text{ lbs}}\right)$$
$$= \left(\frac{120{,}161 \text{ lb } CO_2}{\text{MMscf}}\right) \times \left(\frac{\text{scf}}{918.14 \text{ Btu}}\right) \times \left(\frac{14.7 \text{ MMBtu}}{\text{hr}}\right) \times \left(\frac{8{,}760 \text{ hrs}}{\text{yr}}\right) \times \left(\frac{1 \text{ ton}}{2{,}000 \text{ lbs}}\right)$$
$$= 8{,}426.48 \text{ tpy } CO_2$$

Where F = Emission Factor (lb CO_2/MMscf)
HV = Heating Value of Natural Gas (Btu/scf)
HR = Maximum Heater Firing Rate (MMBtu/hr)

The emission rate of each GHG per regeneration heater is summarized in Table 3.5-1.

Table 3.5-1
Regeneration Heater GHG Emission Rates

Pollutant	Emission Factor (lb/MMscf)	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	120,161	1,923.85	8,426.48
CH_4	2.27	0.04	0.16
N_2O	0.23	0.004	0.02

3.5.2 CO_2e EMISSION RATE ESTIMATES

The total CO_2e emission rate for each regeneration heater is estimated by multiplying the speciated emission rates in Table 3.5-1 by the appropriate GWP in Table 3.2-1.

Table 3.5-2 summarizes the CO_2e emission rates for each regeneration heater at the Hardin County NGL Fractionation Plant.

Table 3.5-2
GHG Emission Rates for All Regeneration Heaters

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
HTR1	CO_2e	1,925.93	8,436.03
HTR2	CO_2e	1,925.93	8,436.03
HTR3	CO_2e	1,925.93	8,436.03
Total	**CO_2e**	**5,777.79**	**25,308.09**

3.6 PROCESS FLARE ROUTINE EMISSIONS

During routine operations, the flare is used to combust vent gases from the Process Waste Water Tanks and the Hydrocarbon Waste Tanks. The methodology used to calculate these waste streams is detailed in Sections 3.10 through 3.12. The flare also combusts a small amount of pilot gas used to maintain flame presence and sweep gas used to maintain flare header pressure.

The flare is also used to control gases from MSS activities. These emissions are discussed in detail in Section 3.13.

3.6.1 NATURAL GAS FUEL COMBUSTION EMISSIONS

The flare combusts 355.21 standard cubic feet per hour ("scf/hr") pilot gas and 450 scf/hr sweep gas. The CO_2 emission factor is based on the MRR, as discussed in Section 3.1. The emission factor for each GHG is presented in Table 3.6-1.

The E_{MAX} of CO_2 from the flare due to the combustion of pilot gas and sweep gas is estimated as follows:

$$E_{MAX}\left(\frac{lb}{hr}\right) = Q \times EF \times \left(\frac{1\ MMscf}{10^6\ scf}\right)$$
$$= \left(\frac{805.21\ scf}{hr}\right) \times \left(\frac{120{,}161\ lb\ CO_2}{MMscf}\right) \times \left(\frac{1\ MMscf}{10^6\ scf}\right)$$
$$= 96.75\ \frac{lb}{hr}\ CO_2$$

Where Q = Fuel Flow Heat Rate (scf/hr)
EF = CO_2 Emission Factor

The E_{ANN} of CO_2 from combustion of the pilot and sweep gas is estimated as follows:

$$E_{ANN}\ (tpy) = Q \times EF \times \left(\frac{1\ MMscf}{10^6\ scf}\right) \times \left(\frac{8{,}760\ hr}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lbs}\right)$$
$$= \left(\frac{805.21\ scf}{hr}\right) \times \left(\frac{120{,}161\ lb\ CO_2}{MMscf}\right) \times \left(\frac{1\ MMscf}{10^6\ scf}\right) \times \left(\frac{8{,}760\ hr}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lbs}\right)$$
$$= 423.79\ tpy\ CO_2$$

Where Q = Fuel Flow Heat Rate (scf/hr)
EF = CO_2 Emission Factor

Table 3.6-1 summarizes the GHG emission rates for the flare from fuel gas combustion.

Table 3.6-1
Flare GHG Emission Rates for Fuel Gas Combustion

Pollutant	Emission Factor (lb/MMscf)	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	120,161	96.75	423.79
CH_4	2.27	0.64	2.80
N_2O	0.23	0.0002	0.001

The total CO_2e emission rate for the flare from burning fuel gas is estimated by multiplying the speciated emission rates in Table 3.6-1 by the appropriate GWP in Table 3.2-1. Table 3.6-2 summarizes the CO_2e emission rates for the flare from burning fuel gas.

Table 3.6-2
Flare GHG Emission Rates from Fuel Gas

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
FLR1	CO_2e	96.85	424.21

3.6.2 VENT GAS COMBUSTION EMISSIONS

COMBUSTION OF CARBON CONTAINING COMPOUNDS IN TANK WASTE GASES – CO_2 EMISSION RATE

The E_{MAX} of CO_2 from combustion of carbon containing compounds in the tank vent gas streams is estimated assuming all carbon in the compound is converted into CO_2 as follows (using n-hexane from the Process Waste Water Tank as an example):

$$E_{MAX}\left(\frac{lb}{hr}\right) = M \times MW_{C6} \times S \times MW_{CO2}$$

$$= \left(\frac{0.24\ lb\ n\text{-}C_6}{hr}\right) \times \left(\frac{lbmol\ n\text{-}C_6}{86.10\ lb\ n\text{-}C_6}\right) \times \left(\frac{6\ lbmol\ CO_2}{lbmol\ n\text{-}C_6}\right) \times \left(\frac{44.01\ lb\ CO_2}{lbmol\ CO_2}\right)$$

$$= 0.74\ \frac{lb}{hr} CO_2$$

Where M = Mass Flow Rate of n-Hexane to the Flare (lb/hr)
MW_{C6} = Molecular Weight of n-Hexane
S = Number of CO_2 molecules generated per molecules of n-Hexane
MW_{CO2} = Molecular Weight of CO_2

The E_{MAX} of CO_2 from combustion of all carbon containing compounds in the tank vent gas streams, calculated as shown above for each compound in the vent gas, is 2.20 lb/hr.

The E_{ANN} of CO_2 from combustion of carbon containing compounds in the tank waste gas streams is estimated assuming all carbon in the compound is converted into CO_2 as follows (using n-hexane from the Process Waste Water Tank as an example):

$$E_{ANN}\ (tpy) = M \times MW_{C6} \times S \times MW_{CO2} \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lb}\right)$$

$$= \left(\frac{0.24\ lb\ n\text{-}C_6}{hr}\right) \times \left(\frac{lbmol\ n\text{-}C_6}{86.10\ lb\ n\text{-}C_6}\right) \times \left(\frac{6\ lbmol\ CO_2}{lbmol\ n\text{-}C_6}\right) \times$$

$$\left(\frac{44.01\ lb\ CO_2}{lbmol\ CO_2}\right) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lb}\right)$$

$$= 3.22\ tpy\ CO_2$$

Where M = Mass Flow Rate of n-Hexane to the Flare (lb / hr)
MW_{C6} = Molecular Weight of n-Hexane
S = Number of CO_2 molecules generated per molecule of n-Hexane
MW_{CO2} = Molecular Weight of CO_2

The E_{ANN} of CO_2 from combustion of carbon containing compounds in the tank vent gas streams, calculated as shown above for each compound in the vent gas, is 9.64 tpy.

COMBUSTION OF TANK WASTE GAS – N_2O EMISSION RATE

The N_2O emission rate from the flare due to combustion of tank vent gas is estimated using Equation W-40, 40 CFR Part 98, Subpart W. Equation W-40 uses a waste gas heating value of 1.235×10^{-3} MMBtu/scf , an emission factor of 1×10^{-4} kg N_2O/MMBtu, and the total molar flow rate of vent gas sent to the flare. The maximum hourly molar flow rate of tank vent gas is estimated as follows (using n-hexane as an example):

$$Mo\left(\frac{\text{lbmol}}{\text{hr}}\right) = M \div MW \times V$$

$$= \left(\frac{0.24\text{ lb n-C}_6}{\text{hr}}\right) \times \left(\frac{1\text{ lbmol n-C}_6}{86.10\text{ lb n-C}_6}\right)$$

$$= 0.00279\ \frac{\text{lbmol n-C}_6}{\text{hr}}$$

Where Mo = Molar Flow Rate of n-Hexane (lbmol/hr)
MW = Molecular Weight of n-Hexane

The total maximum hourly molar flow rate of tank vent gas, calculated as shown above for each compound in the vent gas, is 0.009 lbmol/hr.

The total maximum hourly N_2O emission rate due to combustion of all compounds in tank vent gas is estimated as follows:

$$E_{MAX}\left(\frac{\text{lb}}{\text{hr}}\right) = Mo \times EF \div HV \times V$$

$$= \left(\frac{0.009\text{ lbmol}}{\text{hr}}\right) \times \left(\frac{0.0002\text{ lb }N_2O}{\text{MMBtu}}\right) \times \left(\frac{0.001235\text{ MMBtu}}{\text{scf}}\right) \times \left(\frac{379.5\text{ scf}}{\text{lbmol}}\right)$$

$$= 8.44 \times 10^{-7}\ \frac{\text{lb}}{\text{hr}} N_2O$$

Where Mo = Molar Flow Rate (lbmol/hr)
EF = N_2O Emission Factor
HV = Heating Value of Waste Gas (MMBtu/scf)
V = Standard Molar Volume of Gas (scf/lbmol)

The total annual N_2O emission rate due to combustion of all compounds in tank vent gas is estimated as follows:

$$E_{ANN}\ (typ) = Mo\ \times EF \div HV \times V \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lbs}\right)$$

$$= \left(\frac{0.009\ lbmol}{hr}\right) \times \left(\frac{0.0002\ lb\ N_2O}{MMBtu}\right) \times \left(\frac{0.001235\ MMBtu}{scf}\right) \times \left(\frac{379.5\ scf}{lbmol}\right) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton\ N_2O}{2{,}000\ lbs\ N_2O}\right)$$

$$= 3.70 \times 10^{-6}\ tpy\ N_2O$$

Where Mo = Molar Flow Rate (mol/hr)
EF = N_2O Emission Factor
HV = Heating Value of Waste Gas (MMBtu/scf)
V = Standard Molar Volume of Gas (scf/lbmol)

Table 3.6-3 summarizes the GHG emission rates for the flare from vent gas combustion.

Table 3.6-3
Flare GHG Emission Rates for Tank Vent Gas Combustion

Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	2.20	9.64
CH_4	0	0
N_2O	8.E-07	4.E-06

The total CO_2e emission rate for the flare from burning tank vent gas is estimated by multiplying the speciated emission rates in Table 3.6-3 by the appropriate GWP in Table 3.2-1.

Table 3.6-4 summarizes CO_2e emission rate for the flare from burning tank vent gas.

Table 3.6-4
Flare GHG Emission Rates for Tank Vent Gas Combustion

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
FLR1	CO_2e	2.20	9.64

Table 3.6-5 summarizes the total CO_2e emission rate for the flare from combusting both fuel gas and tank vent gas.

Table 3.6-5
Flare GHG Emission Rates

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
FLR1 – Fuel Gas	CO_2e	96.85	424.21
FLR1 – Waste Gas	CO_2e	2.20	9.64
Total	**CO_2e**	**99.05**	**433.85**

3.7 THERMAL OXIDIZERS

The TO are used to control emissions from the amine unit regeneration vent and off-gas from caustic/gasoline treating from each train. Normal operation TO emissions consist of the combustion of natural gas fuel and combustion of waste gas from the amine unit and off-gas from the caustic/gasoline treating.

3.7.1 NATURAL GAS FUEL COMBUSTION EMISSIONS

The TO uses a burner fueled by natural gas to maintain a flame within the firebox to properly combust waste gases it is used to control. Combustion of the fuel gas results in GHG emissions. The factors used to estimate emissions of CO_2, CH_4, and N_2O are from the MRR, as discussed in Section 3.1. The emission factor for each GHG is presented in Table 3.7-1.

The TO fuel gas heat input is 8.25 MMBtu/hr. The E_{MAX} of CO_2, CH_4, and N_2O from combustion of natural gas are estimated as follows (using CO_2 as an example):

$$E_{MAX}\left(\frac{lb}{hr}\right) = Q \times EF \times \left(\frac{1\ scf}{918.14\ btu}\right)$$
$$= \left(\frac{8.25\ MMBtu}{hr}\right) \times \left(\frac{120{,}161\ lb\ CO_2}{MMscf}\right) \times \left(\frac{1\ scf}{918.14\ btu}\right)$$
$$= 1{,}079.71\ \frac{lb\ CO_2}{hr}$$

Where Q = Fuel Flow Heat Rate (MMBtu/hr)
EF = CO_2 Emission Factor

The E_{ANN} from the TO are based on 8,760 hours per year operation. The E_{ANN} of CO_2, CH_4, and N_2O from combustion of natural gas are estimated as follows (using CO_2 as an example):

$$E_{ANN}\ (tpy) = Q \times EF \times \left(\frac{1\ scf}{918.14\ btu}\right) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lbs}\right)$$
$$= \left(\frac{8.25\ MMBtu}{hr}\right) \times \left(\frac{120{,}161\ lb\ CO_2}{MMscf}\right) \times \left(\frac{1\ scf}{918.14\ btu}\right) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lbs}\right)$$
$$= 4{,}729.15\ tpy\ CO_2$$

Where Q = Fuel Flow Heat Rate (MMBtu/hr)
EF = CO_2 Emission Factor

Table 3.7-1 summarizes the GHG emission rates for the TO from fuel gas combustion.

Table 3.7-1
TO GHG Emission Rates from Fuel Gas Combustion

Pollutant	Emission Factor (lb/MMscf)	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	120,161	1,079.71	4,729.15
CH_4	2.27	0.02	0.09
N_2O	0.23	0.002	0.01

The total CO_2e emission rate for the TO from burning fuel gas is estimated by multiplying the speciated emission rates in Table 3.7-1 by the appropriate GWP in Table 3.2-1.

Table 3.7-2 summarizes the CO_2e emission rates for the TOs from burning fuel gas.

Table 3.7-2
TO GHG Emission Rates for Fuel Gas Combustion

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
TO1	CO_2e	1,080.75	4,733.83
TO2	CO_2e	1,080.75	4,733.83
TO3	CO_2e	1,080.75	4,733.83
Total	**CO_2e**	**3,242.25**	**14,201.49**

3.7.2 WASTE GAS COMBUSTION EMISSIONS

Emissions of GHGs from waste gas streams routed to the TO are the result of combustion of carbon compounds in the waste gas stream, the portion of CH_4 in the waste gas steam that is not destroyed, and CO_2 in the waste gas stream that passes through the TO unchanged. The composition of the waste gas streams routed to the TO was provided as part of the heat and material balance prepared by the company engineering the plant. The compositions for the waste gas streams routed to the TO were generated using process modeling software. Information on waste gas stream compositions is provided in the detailed emission estimates in Section 6, Attachment B.

CO_2 RESULTING FROM COMBUSTION OF CARBON CONTAINING COMPOUNDS IN WASTE GAS

The E_{MAX} of CO_2 from combustion of carbon containing compounds in the waste gas streams is estimated as follows (using n-hexane from the Caustic/Gasoline Treating Unit as an example):

$$E_{MAX}\left(\frac{lb}{hr}\right) = M \times MW_{C6} \times S \times MW_{CO2}$$
$$= \left(\frac{4.31\ lb\ n\text{-}C_6}{hr}\right) \times \left(\frac{lbmol\ n\text{-}C_6}{86.10\ lb\ n\text{-}C_6}\right) \times \left(\frac{6\ lbmol\ CO_2}{lbmol\ n\text{-}C_6}\right) \times \left(\frac{44.01\ lb\ CO_2}{lbmol\ CO_2}\right)$$
$$= 13.22\ \frac{lb}{hr} CO_2$$

Where M = Mass Flow Rate of n-Hexane to the Thermal Oxidizer (lb/hr)
MW_{C6} = Molecular Weight of n-Hexane
S = Number of CO_2 molecules generated per molecule of n-Hexane
MW_{CO2} = Molecular Weight of CO_2

The maximum hourly emission rate of CO_2 from combustion of all carbon containing compounds in the waste gas streams is 1,110.52 lb/hr.

The E_{ANN} of CO_2 from combustion of all carbon containing compounds in the waste gas streams is estimated as follows (using n-hexane from the Caustic/Gasoline Treating Unit as an example):

$$E_{ANN}\ (tpy) = M \times MW_{C6} \times S \times MW_{CO2} \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lb}\right)$$
$$= \left(\frac{4.31\ lb\ n\text{-}C_6}{hr}\right) \times \left(\frac{lbmol\ n\text{-}C_6}{86.10\ lb\ n\text{-}C_6}\right) \times \left(\frac{6\ lbmol\ CO_2}{lbmol\ n\text{-}C_6}\right) \times \left(\frac{44\ lb\ CO_2}{lbmol\ CO_2}\right) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lb}\right)$$
$$= 57.88\ tpy\ CO_2$$

Where M = Mass Flow Rate of n-Hexane to the Thermal Oxidizer (lb/hr)
MW_{C6} = Molecular Weight of n-Hexane
S = Number of CO_2 molecules generated per molecule of n-Hexane
MW_{CO2} = Molecular Weight of CO_2

The E_{ANN} of CO_2 from combustion of carbon containing compounds in the waste gas streams is 4,864.06 tpy.

CO_2 IN WASTE GAS

The total CO_2 in the waste gas streams that passes through the TO unchanged is 1,708.18 lb/hr and 7,481.83 tpy. These numbers were provided in the heat and material balance and do not require additional calculations. See detailed emission estimates in Section 6, Attachment B.

UNCOMBUSTED CH_4 FROM WASTE GAS

The TOs have a destruction removal efficiency ("DRE") of 99.9%. The E_{MAX} of CH_4 from uncombusted CH_4 in the waste gas streams is estimated as follows (using CH_4 from the Caustic/Gasoline Treating Unit as an example):

$$E_{MAX}\left(\frac{lb}{hr}\right) = ER \times (100\% - DRE\%)$$
$$= \left(60.79\ \frac{lb\ CH_4}{hr}\right) \times (100\% - 99.9\%)$$
$$= 0.06\ \frac{lb}{hr} CH_4$$

Where ER = Methane Emission Rate in Waste Gas (lb/hr)
DRE = TO Destruction Efficiency

The total uncombusted CH_4 in all waste gas streams is 0.06 lb/hr.

The maximum E_{ANN} of CH_4 from uncombusted CH_4 in the waste gas streams is estimated as follows (using CH_4 from the Caustic/Gasoline Treating Unit as an example):

$$E_{ANN}\ (tpy) = ER \times (100\% - DRE\%) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lb}\right)$$
$$= \left(60.79\ \frac{lb\ CH_4}{hr}\right) \times (100\% - 99.9\%) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton\ CH_4}{2{,}000\ lb\ CH_4}\right)$$
$$= 0.27\ tpy\ CH_4$$

Where ER = Methane Emission Rate in Waste Gas (lb/hr)
DRE = TO Destruction Efficiency

The total uncombusted CH_4 in all waste gas streams is 0.27 tpy.

N_2O RESULTING FROM COMBUSTION OF WASTE GAS

The N_2O emission rate from the TO due to combustion of vent gas is calculated using Equation W-40, 40 CFR Part 98, Subpart W. Equation W-40 uses a waste gas heating value of 1.235×10^{-3} MMBtu/scf and an emission factor of 1×10^{-4} kg N_2O/MMBtu.

The maximum hourly molar flow rate of vent gas is estimated as follows (using n-hexane from the caustic/gasoline treating vent as an example):

$$Mo\left(\frac{scf}{hr}\right) = M \div MW \times V$$

$$= \left(\frac{4.31\ lb\ n\text{-}C_6}{hr}\right) \times \left(\frac{1\ lbmol\ n\text{-}C_6}{86.10\ lb\ n\text{-}C_6}\right)$$

$$= 0.05\ \frac{lbmol\ n\text{-}C_6}{hr}$$

Where Mo = Molar Flow Rate of n-Hexane (lbmol/hr)
MW = Molecular Weight of n-Hexane

The total maximum hourly molar flow rate of tank vent gas is 9.86 scf/hr.

The total maximum hourly N_2O emission rate due to combustion of all compounds in vent gas is estimated as follows:

$$E_{MAX}\left(\frac{lb}{hr}\right) = Mo \times EF \div HV \times V$$

$$= \left(\frac{9.86\ lbmol}{hr}\right) \times \left(\frac{0.0002\ lb\ N_2O}{MMBtu}\right) \times \left(\frac{0.001235\ MMBtu}{scf}\right) \times \left(\frac{379.5\ scf}{lbmol}\right)$$

$$= 9.2 \times 10^{-4}\ \frac{lb\ N_2O}{hr}$$

Where Mo = Molar Flow Rate (lbmol/hr)
EF = N_2O Emission Factor
HV = Heating Value of Waste Gas (MMBtu/scf)
V = Standard Molar Volume of Gas (scf/lbmol)

The total annual N_2O emission rate due to combustion of all compounds in vent gas is estimated as follows:

$$E_{ANN}\left(\frac{lb}{hr}\right) = Mo \times EF \div HV \times V \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lbs}\right)$$

$$= \left(\frac{9.86\ lbmol}{hr}\right) \times \left(\frac{0.0002\ lb\ N_2O}{MMBtu}\right) \times \left(\frac{0.001235\ MMBtu}{scf}\right) \times$$

$$\left(\frac{379.5\ scf}{lbmol}\right) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton\ N_2O}{2{,}000\ lbs\ N_2O}\right)$$

$$= 4.0 \times 10^{-3}\ tpy\ N_2O$$

Where Mo = Molar Flow Rate (lbmol/hr)
EF = N_2O Emission Factor
HV = Heating Value of Waste Gas (MMBtu/scf)
V = Standard Molar Volume of Gas (scf/lbmol)

Table 3.7-3 summarizes the GHG emission rates for the TO from vent gas combustion.

Table 3.7-3
TO GHG Emission Rates for Vent Gas Combustion

Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	2,818.70	12,345.89
CH_4	0.06	0.27
N_2O	9.E-04	4.E-03

The total CO_2e emission rate for the TO from burning vent gas is estimated by multiplying the speciated emission rates in Table 3.7-3 by the appropriate GWP in Table 3.2-1.
Table 3.7-4 summarizes the speciated GHG and CO_2e emission rates for the TO from burning vent gas.

Table 3.7-4
TO GHG Emission Rates for Vent Gas Combustion

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
TO1	CO_2e	2,820.27	12,352.80
TO2	CO_2e	2,820.27	12,352.80
TO3	CO_2e	2,820.27	12,352.80
Total	**CO_2e**	**8,460.81**	**37,058.40**

Table 3.7-5 summarizes the total CO_2e emission rate for the TOs from combusting both fuel gas and vent gas.

Table 3.7-5
TO GHG Emission Rates

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
TO1 – Fuel Gas	*CO_2e*	*1,080.75*	*4,733.83*
TO1 – Waste Gas	*CO_2e*	*2,820.27*	*12,352.80*
TO1 - Total	CO_2e	3,901.02	17,086.63
TO2 - Total	CO_2e	3,901.02	17,086.63
TO3 - Total	CO_2e	3,901.02	17,086.63
Total	**CO_2e**	**11,703.06**	**51,259.89**

3.8 FIREWATER PUMP ENGINE

3.8.1 CO_2, CH_4, N_2O EMISSION RATE ESTIMATES

The CO_2, CH_4, and N_2O emission factors are from the MRR, as discussed in Section 3.1, for Distillate Fuel Oil No. 2. The emission factors are converted from kg/MMBtu to lb/MMBtu as follows (using CO_2 as an example):

$$\left(\frac{73.96\ \text{kg } CO_2}{\text{MMBtu}}\right) \times \left(\frac{2.2046\ \text{lb } CO_2}{\text{kg } CO_2}\right) = 163.05\ \frac{\text{lb } CO_2}{\text{MMBtu}}$$

The fuel consumption of the engine is estimated using AP-42 Table 3-3.1, Footnote A for diesel fired engines. The heat input rate of the engine is estimated as follows:

$$\begin{aligned} HR\left(\frac{\text{MMBtu}}{\text{hr}}\right) &= HP \times FC \times \left(\frac{1\ \text{MMBtu}}{10^6\ \text{Btu}}\right) \\ &= (265\ \text{hp}) \times \left(\frac{7{,}000\ \text{Btu}}{\text{hp}-\text{hr}}\right) \times \left(\frac{1\ \text{MMBtu}}{10^6\ \text{Btu}}\right) \\ &= 1.86\ \frac{\text{MMBtu}}{\text{hr}} \end{aligned}$$

Where HP = Engine Horsepower Rating
FC = Engine Estimated Fuel Consumption

The E_{MAX} are estimated as follows (using CO_2 as an example):

$$\begin{aligned} E_{MAX}\left(\frac{\text{lb}}{\text{hr}}\right) &= HR \times EF \\ &= \left(\frac{1.86\ \text{MMBtu}}{\text{hr}}\right) \times \left(\frac{163.05\ \text{lb}\ CO_2}{\text{MMBtu}}\right) \\ &= 303.27\ \frac{\text{lb}\ CO_2}{\text{hr}} \end{aligned}$$

Where HR = Maximum Hourly Heat Rate
EF = CO_2 Emission Factor

The E_{ANN} are estimated as follows (using CO_2 as an example):

$$\begin{aligned} E_{ANN}\ (\text{tpy}) &= HR \times EF \times \left(\frac{500\ \text{hrs}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton}}{2{,}000\ \text{lb}}\right) \\ &= \left(\frac{1.86\ \text{MMBtu}}{\text{hr}}\right) \times \left(\frac{163.05\ \text{lb}\ CO_2}{\text{MMBtu}}\right) \times \left(\frac{500\ \text{hrs}}{\text{yr}}\right) \times \left(\frac{1\ \text{ton}}{2{,}000\ \text{lb}}\right) \\ &= 75.82\ \text{tpy}\ CO_2 \end{aligned}$$

Where HR = Maximum Hourly Heat Rate
EF = CO_2 Emission Factor

Table 3.8-1 summarizes the GHG emission rates for the firewater pump engine.

Table 3.8-1
Firewater Pump Engine GHG Emission Rates

Pollutant	Emission Factor (lb/MMBtu)	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	163.05	303.27	75.82
CH_4	0.007	0.01	0.003
N_2O	0.001	0.002	0.001

3.8.2 CO_2e EMISSION RATE ESTIMATE

The total CO_2e emission rate for the firewater pump engine is estimated by multiplying the speciated emission rates in Table 3.8-1 by the appropriate GWP in Table 3.2-1.

Table 3.8-2 summarizes the CO_{2e} emission rates for the firewater pump engine.

Table 3.8-2
Firewater Pump Engine GHG Emission Rates

EPN	Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
ENG1	CO_{2e}	304.10	76.03

3.9 EQUIPMENT COMPONENT FUGITIVE EMISSION RATES

Some equipment components within the Hardin County NGL Fractionation Plant are potential sources of CO_2 and CH_4 emissions due to leaking valves, flanges, seals, etc. The acid gas stream, for example, includes approximately 93.003% (weight percent) CO_2 (see Section 6, Attachment B). Therefore, in the event of any equipment component leaks, a small amount of GHGs could be emitted to the atmosphere.

Potential GHG emissions from leaking equipment components are estimated using emission factors in the TCEQ's technical guidance for "Equipment Leak Fugitives" (October 2000) for Oil and Gas Facilities. DCP will implement a 28M monitoring program to control the emissions from equipment leak fugitives.

The maximum hourly CO_2 emissions, using gas valves in acid gas service as an example, are estimated as follows:

$$E_{MAX}\left(\frac{lb}{hr}\right) = N \times EF \times (100\% - \%R) \times \%CO_2$$
$$= (88) \times \left(\frac{0.00992\ lb}{hr\text{-}component}\right) \times (100\% - 75\%) \times (93.003\%)$$
$$= 0.20\ \frac{lb\ CO_2}{hr}$$

Where N = Number of Components
EF = Equipment Leak Emission Factor
%R = Monitoring Program Control Efficiency
$\%CO_2$ = Weight Percent CO_2 in Emission Stream

Annual emissions of CO_2 from gas valves in acid gas service are estimated as follows:

$$E_{ANN}\ (tpy) = N \times EF \times (100\% - \%R) \times \%CO_2 \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lb}\right)$$
$$= (88) \times \left(\frac{0.00992\ lb}{hr\text{-}component}\right) \times (100\% - 75\%) \times (93.003\%) \times \left(\frac{8{,}760\ hrs}{yr}\right) \times \left(\frac{1\ ton}{2{,}000\ lb}\right)$$
$$= 0.89\ tpy\ CO_2$$

Where N = Number of Components
EF = Equipment Leak Emission Factor
%R = Monitoring Program Control Efficiency
$\%CO_2$ = Weight Percent CO_2 in Emission Stream

Total maximum CO_2 and CH_4 emissions for all components in all streams are calculated using the method described above and are equal to 0.28 lb/hr and 1.23 tpy CO_2, and 1.30 lb/hr and 5.69 tpy CH_4.

The total CO_2e emission rate for the equipment leak fugitives is estimated by multiplying the speciated emission rates in by the appropriate GWP in 3.2-1, and is estimated to be 27.57 lb/hr and 120.75 tpy, per train.

3.10 AMINE STORAGE TANK

The amine systems at the Hardin County NGL Fractionation Plant include three 119 barrel ("bbl") fixed roof storage tanks for fresh amine, one tank per train. The amine, Dow UCARSOL, is a mixture of 60 percent by weight ("wt%") water, 33 wt% methyldiethanolamine ("MDEA"), and 7 wt% piperazine. The vapor from the vessel is routed to the process flare. The vapor phase speciation, molecular weight, and vapor pressure are calculated using engineering principles and the vapor pressure data presented on the applicable Material Safety Data Sheet ("MSDS"). The MSDS is contained in Section 6, Attachment B. The emissions from each tank are estimated using the equations presented in AP-42, Section 7.2 for storage tanks.

The storage tanks will be maintained under pressure and therefore will not continuously vent to the flare. To calculate the worst case hourly and annual tank emissions, DCP has conservatively assumed the tanks will be continuously filled and vented to the flare. The maximum hourly emission rate is calculated assuming the tank will be filled once during any one hour period (119 bbl/hr; 4,998 gal/hr). The maximum E_{ANN} is calculated by conservatively assuming the tank is filling continuously for 8,760 hrs/yr, or using a maximum throughput of 1,042,440 bbl/yr (43,782,480 gal/yr). Detailed emission estimates are included in Section 6, Attachment B. Estimated emissions from this tank are input as a portion of the tank vent gases used to estimate GHG emissions resulting from combustion of tank vent gases in the flare, as described in Section 3.6.

3.11 PROCESS WASTE WATER TANK

The Hardin County NGL Fractionation will include three 11,000 gallon process waste water storage tanks, one tank per train. The process waste water tank is conservatively assumed to contain 1% Y-grade feed and 99% water. The emissions from the tank are estimated using the equations presented in AP-42, Section 7.2 for storage tanks.

The storage tanks will be maintained under pressure and therefore will not continuously vent to the flare. To calculate the worst case hourly and annual tank emissions, DCP has conservatively assumed the tanks will be continuously filled and vented to the flare. The maximum hourly emission rate is estimated by conservatively assuming the tank will fill at a maximum rate of 4.8 bbl/hr (201.6 gal/hr). The maximum E_{ANN} is estimated by conservatively assuming the tank is filling continuously for 8,760 hrs/yr, or using a maximum throughput of 42,048 bbl/yr (1,766,016 gal/yr). Detailed emission estimates are included in Section 6, Attachment B. Estimated emissions from this tank are input as a portion of the tank vent gases used to estimate GHG emissions resulting from combustion of tank vent gases in the flare, as described in Section 3.6.

3.12 HYDROCARBON WASTE STORAGE TANK

The Hardin County NGL Fractionation plant will include three 1,000 gal hydrocarbon waste storage tanks, one tank per train. The hydrocarbon waste storage tank is assumed to contain 100% Y-grade feed. The emissions from the tank are estimated using the equations presented in AP-42, Section 7.2 for storage tanks.

The storage tanks will be maintained under pressure and therefore will not continuously vent to the flare. To calculate the worst case hourly and annual tank emissions, DCP has conservatively assumed the tanks will be continuously filled and vented to the flare. The maximum hourly emission rate is calculated assuming the tank will fill at a maximum rate of 0.24 bbl/hr (10.08 gal/hr). The maximum E_{ANN} is calculated by conservatively assuming the tank is filling continuously for 8,760 hrs/yr, or using a maximum throughput of 2,102.4 bbl/yr (88,300.8 gal/yr). Detailed emission estimates are included in Section 6, Attachment B. Estimated emissions from this tank are input as a portion of the tank vent gases used to estimate GHG emissions resulting from combustion of tank vent gases in the flare, as described in Section 3.6.

3.13 MSS ACTIVITIES

Several sources within the Hardin County NGL Fractionation Plant will experience emissions during plant MSS activities that are in addition to the "normal operations" emission rates described in Sections 3.3 through 3.12 of this application. Waste gases associated with MSS emissions are routed to the flare (EPN: FLR1). For maximum hourly emission estimate purposes, all activities are conservatively assumed to occur during the same one hour period. Annual emission estimates are based on the number of times each activity is expected to occur per year. Activities that can result in MSS emissions include, but are not limited to, the following, shown in Table 3.13-1:

Table 3.13-1
List of MSS Activities

Maintenance Activity	Quantity Flared (lbs)	Material Flared	Frequency
Change Feed Coalescer Elements	7,500	Mixed NGL	1/yr
Change Lean Amine Filters	5	Fuel Gas	3/yr
Change Lean Amine carbon	60	Fuel Gas	2/yr
Repair Ethane Product Pump Seals	600	Ethane	1/yr
Repair Propane Reflux Pump Seals	50	Propane	2/yr
Change Gasoline Product Filter	175	Natural Gasoline	1/yr
Repair Propane Compressor Seals	30	Propane	1/yr
Wash Propane Compressor Turbine	5	Propane	4/yr
Change Hot Oil Filter	5	Fuel Gas	1/2 yrs

Emissions of GHGs from MSS gas streams routed to the flare during MSS are the result of combustion of carbon compounds in the MSS gas stream, the portion of CH_4 in the MSS gas steam that is not destroyed, and CO_2 in the MSS gas stream that passes through the flare unchanged. The composition of the MSS gas streams routed to the flare was provided as part of the heat and material balance prepared by the engineering company. The compositions for the MSS gas streams routed to the flare were generated using process modeling software. Information on MSS gas stream compositions is provided in the detailed emission estimates in

Section 6, Attachment B. GHG emission rates from the flare during MSS are estimated using the same calculation methodologies outlined in Section 3.6.2.

Table 3.13-2 summarizes the GHG emission rates for the flare from MSS gas combustion.

Table 3.13-2
Flare GHG Emission Rates for MSS Gas Combustion

Pollutant	E_{MAX} (lb/hr)	E_{ANN} (tpy)
CO_2	29,021.17	14.52
CH_4	3.15	0.002
N_2O	0.02	$10x10^{-5}$
CO_2e	29,108.79	14.55

4.0 REGULATORY APPLICABILITY ANALYSIS

This section addresses applicability of federal air quality regulations with respect to GHG emissions and PSD regulatory review.

4.1 PSD APPLICABILITY

4.1.1 GENERAL PSD STATIONARY SOURCE APPLICABILITY

Federal PSD regulations are codified in CFR Title 40, Part 52, Subpart A, Section 21. PSD regulations are potentially applicable to any existing major stationary source or new major stationary source that emits a regulated New Source Review ("NSR") pollutant that is located in an area designated as attainment or unclassifiable under Sections 107(d)(1)(A)(ii) or (iii) of the Clean Air Act ("CAA"), as described in 40 CFR §52.21(a)(2). A major stationary source is defined in 40 CFR §52.21(b)(1)(i) as either 1) any stationary source that emits or has the potential to emit 100 tpy or more of any regulated NSR pollutant if it is one of the 26 types of sources listed in 40 CFR §52.21(b)(1)(i)(a), or 2) any stationary sources that emits or has the potential to emit 250 tpy or more of any regulated NSR pollutant. Regulated NSR pollutants, as defined in 40 CFR §52.21(b)(50), include the following:

- CO
- Lead ("Pb")
- Nitrogen Dioxide ("NO_2")
- Ozone ("O_3") – precursors are VOC and NO_X
- PM_{10}
- $PM_{2.5}$ – precursors are SO_2 and NO_X
- SO_2
- Asbestos ("ASB")
- Beryllium ("Be")
- Mercury ("Hg")
- Vinyl chloride ("VC")

- Fluorides
- Sulfuric acid (“H_2SO_4”) mist
- Hydrogen sulfide (“H_2S”)
- Total reduced sulfur compounds (“TRS”)
- GHGs, which are comprised of the aggregate group of six GHGs: CO_2, N_2O, CH_4, hydrofluorocarbons (“HFCs”), perfluorocarbons (“PFCs”), and sulfur hexafluoride (“SF_6”)

EXISTING SOURCE APPLICABILITY

PSD regulatory review applies to an existing major stationary source if the source performs a project that is considered a major modification that causes a significant emissions increase and a significant net emissions increase of a regulated NSR pollutant, as described in 40 CFR §52.21(a)(2)(iv)(a). The emissions increase calculation may be based on either the comparison of baseline actual emission to potential to emit methodology or the comparison of baseline actual emissions to future potential to emit methodology described in 40 CFR §§52.21(a)(2)(iv)(c) and (d), respectively. A significant emissions increase as defined in 40 CFR §52.21(b)(40), is an increase in emissions of non-GHG or GHG pollutants that is equal to or greater than the rates listed below, as represented in 40 CFR §52.21(b)(23)(i) and 40 CFR §52.21(b)(49)(iii), respectively:

- CO: 100 tpy
- NO_X: 40 tpy
- SO_2: 40 tpy
- Particulate matter: 25 tpy
- PM_{10}: 15 tpy
- $PM_{2.5}$: 10 tpy
- O_3: 40 tpy of VOC or NO_X
- Pb: 0.6 tpy
- Fluorides: 3 tpy
- H_2SO_4 mist: 7 tpy

- H_2S: 10 tpy
- TRS: 10 tpy
- Reduced sulfur compounds: 10 tpy
- CO_2e: 75,000 tpy

PSD regulatory review also applies to any existing stationary source that emits of has the potential to emit 100,000 tpy CO_2e or more, when the source performs a project that causes a significant emissions increase and a significant net emissions increase of 75,000 tpy CO_2e or more, as described in 40 CFR §52.21(b)(49)(v)(b).

This information on existing sources applicability is provided for informational purposes only. The proposed Hardin County NGL Fractionation Plant will be a new stationary source; therefore, the existing source requirements do not apply.

NEW SOURCE APPLICABILITY

As described in 40 CFR §52.21(b)(1)(i) and 40 CFR §§52.21(b)(49)(iv) and (v), PSD regulatory review applies to a new major stationary source that emits or has the potential to emit pollutants in the quantities described below:

- 100 tpy or more of any regulated NSR pollutant (other than GHGs) if it is one of the 26 types of sources listed in 40 CFR §52.21(b)(1)(i)(a)
- 250 tpy or more of any regulated NSR pollutant (other than GHGs)
- 100,000 tpy CO_2e

4.1.2 HARDIN COUNTY NGL FRACTIONATION PLANT PSD APPLICABILITY

The proposed Hardin County NGL Fractionation Plant will be classified as a new stationary source. Because the site is a new and not existing stationary source, to determine applicability of PSD regulatory review to the proposed plant the potential annual emissions of regulated NSR pollutants must be compared to the PSD major source emission thresholds in 40 CFR

§52.21(b)(1)(i) and 40 CFR §§52.21(b)(49)(iv) and (v). If the new stationary source is determined to be a major stationary source for any regulated NSR pollutant (per the comparison in the previous sentence), the potential emission rate of each of the other minor regulated NSR pollutants must be compared to that pollutant's significant emissions threshold in 40 CFR §52.21(b)(23)(i) and 40 CFR §52.21(b)(49)(iii) to determine if the resulting emissions represent a major modification with respect to the remaining pollutants.

As described in Section 3.0, emissions from the proposed plant include the regulated NSR pollutants CO, NO_X, VOC, PM_{10}, $PM_{2.5}$, SO_2, H_2S, TRS, and CO_2e. Table 4-1 provides a summary of the potential emission rates of all regulated NSR pollutants as compared to the major source and significant emissions thresholds. As shown in Table 4-1, the proposed facility is a major stationary source due to emissions of NO_X, CO and CO_2e and a major modification with respect to emissions of VOC, SO_2, PM_{10}, and $PM_{2.5}$. Therefore, PSD regulatory review is required for emissions of CO, NO_X, VOC, PM_{10}, $PM_{2.5}$, SO_2, and CO_2e from the proposed facility. The TCEQ is the delegated authority for permitting of non-GHG pollutants; therefore, the PSD application associated with emissions of CO, NO_X, VOC, PM_{10}, $PM_{2.5}$, and SO_2 will be submitted to the TCEQ. The non-GHG PSD permit application submitted to the TCEQ will also be copied to USEPA Region 6.

Table 4-1
Comparison of Proposed Site Emission Rates to PSD Major Source and Major Modification Threshold

Pollutant	Emission Rate (tpy)	Major Source Threshold (tpy)	Major Modification Threshold (tpy)
CO_2e	662,858	100,000	75,000
NO_X	286	250	40
CO	364	250	100
VOC	171	250	40
SO_2	155	250	40
$PM_{10}/PM_{2.5}$	82	250	15/10
H_2S	0.01	250	10
TRS	0.05	250	10

4.2 PSD REGULATORY REVIEW REQUIREMENTS

Because PSD regulatory review is applicable to the Hardin County NGL Fractionation Plant as described in Section 4.1.2, the facility must meet the applicable PSD regulatory review requirements contained in 40 CFR §§52.21(c) through (w). This section addresses the PSD regulatory review requirements applicable to the proposed facility, PSD requirements concerning non-GHG pollutants are addressed in the non-GHG PSD permit application submitted to the TCEQ.

4.2.1 COMPLIANCE WITH EMISSION LIMITATIONS AND STANDARDS

As described in 40 CFR §52.21(j)(1), any major stationary source or major modification must meet each applicable emission limitation under the State Implementation Plan ("SIP") and each applicable emission standard and standard of performance under 40 CFR parts 60 and 61. Applicability of and compliance with emission limitations under the TCEQ SIP, New Source Performance Standard ("NSPS") in 40 CFR Part 60, and National Emission Standards for Hazardous Air Pollutants ("NESHAPs") in 40 CFR Part 61 are addressed in the non-GHG PSD permit application submitted to the TCEQ.

4.2.2 BEST AVAILABLE CONTROL TECHNOLOGY

As described in 40 CFR §52.21(j)(2) and (3), any major stationary source or major modification must apply BACT for each regulated NSR pollutant that the source would have the potential to emit in significant amounts. The regulated NSR pollutants that the facility will have the potential to emit in significant amounts include CO, NO_X, VOC, PM_{10}, $PM_{2.5}$, SO_2, and CO_2e. A BACT analysis for CO_2e, which includes emissions of CO_2, CH_4, and N_2O, is included in Section 5.0 of this application. A BACT analysis for all other regulated NSR pollutants proposed to be emitted in significant amounts will be included in the non-GHG PSD permit application submitted to the TCEQ.

4.2.3 SOURCE IMPACT ANALYSIS

As described in 40 CFR §52.21(k)(1), a demonstration is required to show that emission increases of regulated NSR pollutants subject to PSD regulatory review associated with the proposed facility will not cause or contribute to air pollution in violation of either of the following:

- Any National Ambient Air Quality Standard ("NAAQS")
- Any applicable maximum allowable increase over the baseline concentration ("PSD increment")

The regulated NSR pollutants for which NAAQS have been promulgated include CO, Pb, NO_2, O_3, $PM_{2.5}$, PM_{10}, and SO_2. The PSD increments include emissions of NO_2, $PM_{2.5}$, PM_{10}, and SO_2, as provided in 40 CFR §52.21(c). Estimates of ambient air quality for both NAAQS and PSD increment evaluations must be based on applicable air quality models specified in Appendix W of 40 CFR Part 51, as described in 40 CFR §52.21(l)(1).

The regulated NSR pollutants that will be emitted from the proposed facility for which a source impact analysis is required are CO, NO_2, $PM_{2.5}$, PM_{10}, and SO_2. Because potential emissions of NO_X and VOC exceed 100 tpy each and both pollutants are considered precursors to O_3, an ambient impact analysis is required for these pollutants as described in the note to 40 CFR §52.21(i)(5)(i)(f). A source impact analysis for these non-GHG pollutants is addressed in the non-GHG PSD permit application submitted to TCEQ.

Although CO_2e is a regulated NSR pollutant, a source impact analysis is not required for this pollutant because no NAAQS or PSD increment exists for this pollutant. As described in Section IV page 48 of the USEPA's PSD and Title V Permitting Guidance for Greenhouse Gases, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews.

4.2.4 AMBIENT AIR QUALITY ANALYSIS

As described in 40 CFR §52.21(m)(1)(i), an ambient air quality analysis must be submitted with any permit application for each pollutant that the source has the potential to emit in a significant amount. This analysis must include air quality monitoring data as required by 40 CFR §§52.21(m)(1)(ii) and (iii), unless exempted from the requirements of 40 CFR §52.21(m) as described in 40 CFR §52.21(i)(5). Exemptions from the monitoring requirements for a pollutant may be granted by the permitting authority in the following cases:

- 40 CFR §52.21(i)(5)(i) – The emissions increase of the pollutant from the new source would result in air quality impacts less than the concentration listed in 40 CFR 52.21(i)(5)(i)(a) through (k) for that pollutant.
- 40 CFR §52.21(i)(5)(ii) – The existing concentrations of the pollutant in the area the new source would affect are less than the concentration listed in 40 CFR 52.21(i)(5)(i)(a) through (k) for that pollutant.
- 40 CFR 52.21(i)(5)(iii) – The pollutant is not listed in 40 CFR 52.21(i)(5)(i).

To determine if the first exemption above applies the source impact analysis using dispersion modeling must be conducted, as described in Section 4.2.3. To determine if the second exemption above applies a combination of dispersion modeling of existing sources and existing ambient monitoring data may be used.

As discussed in Section 4.1.2 the pollutants that have the potential to be emitted in significant amounts from the proposed facility are CO, NO_X, VOC, PM_{10}, $PM_{2.5}$, SO_2, and CO_2e. Ambient air quality analysis requirements for CO, NO_X, VOC, PM_{10}, $PM_{2.5}$, and SO_2 are addressed in the non-GHG PSD permit application submitted to TCEQ. Emissions of CO_2e are exempt from the ambient air quality analysis requirements per the exemption in 40 CFR §52.21(i)(5)(iii).

4.2.5 SOURCE INFORMATION

As described in 40 CFR §52.21(n), the owner or operator of the proposed source is required to submit all information necessary to perform any analysis or make any determination required under the PSD regulations.

Information pertaining to the design and construction of the source required by 40 CFR §52.21(n)(1) that must be submitted includes the following:

- A description of the nature, location, design capacity, and typical operating schedule of the proposed source.
- Specifications and drawings showing the source design and plant layout.
- A detailed schedule of construction of the source.
- A detailed description as to what system of continuous emission reduction is planned, emission estimates, and any other information necessary to determine BACT would be applied.

Information concerning design and construction of the source is provided in this GHG PSD permit application and the non-GHG PSD permit application submitted to the TCEQ. Information regarding the nature, location, design capacity, typical operating schedule, and drawings of plant design and layout of the proposed source are provided in Sections 1.0, 2.0, and 3.0 of this application. Proposed start of construction and start of operation dates are included in the PI-1 form in Section 6, Attachment A. Information regarding emission estimates and BACT for GHG pollutants is included in Sections 3.0 and 5.0 of this application, respectively. Information regarding emission estimates and BACT for non-GHG pollutants is included in the non-GHG PSD permit application submitted to the TCEQ. The non-GHG PSD permit application submitted to the TCEQ will also be copied to USEPA Region 6.

Information pertaining to ambient air quality impacts from the proposed source and other sources in the area affected by the source as required by 40 CFR §52.21(n)(2) includes the following:

- The air quality impact of the source.
- Meteorological and topographical data necessary to estimate the impact of the source.
- The air quality impacts, and nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977.

Air quality impacts associated with the proposed facility and any general commercial, residential, industrial, or other growth are covered by the requirements addressed in Sections 5.2.3 and 5.2.4 of this application. This requirement applies to non-GHG pollutants only, as noted in the referenced sections. Specific information regarding non-GHG pollutants is included in the non-GHG PSD permit application submitted to the TCEQ.

4.2.6 ADDITIONAL IMPACTS ANALYSES AND FEDERAL CLASS I AREA IMPACTS

As described in 40 CFR §52.21(o), an analysis is required of the impacts that may result from the proposed source:

- 40 CFR §52.21(o)(1) - An analysis of impairment to visibility, soils, and vegetation that would occur as a result of the source and general commercial, residential, industrial and other growth associated with the source.
- 40 CFR §52.21(o)(2) - An analysis of the air quality impact for the area as a result of general commercial, residential, industrial and other growth associated with the source.
- 40 CFR §52.21(o)(3) - Visibility monitoring may be required in any Federal Class I area near the proposed source.

As described in 40 CFR §52.21(p), a visibility analysis may be required for emissions from major sources that may affect a Class I area. Whether or not the analysis projects that a Class I increment in 40 CFR §52.21(p)(5) may be violated determines whether the burden of proof is on the Federal Land Manager or the applicant to demonstrate that the source's emissions would have no adverse impact in the Class I area.

As described in the USEPA PSD and Title V Permitting Guidance for Greenhouse Gases, Section IV (Other PSD Requirements), dated March 2011, it is not necessary to assess impacts from GHGs in the context of the additional impacts analysis or the Class I area impacts. Additional impacts analysis and Class I area impacts for non-GHG pollutants are addressed in the non-GHG PSD permit application submitted to the TCEQ.

4.2.7 ENVIRONMENTAL IMPACT STATEMENTS

As described in 40 CFR §52.21(s), whenever any proposed source is subject to action by a Federal Agency which might necessitate preparation of an environmental impact statement ("EIS") pursuant to the National Environmental Policy Act ("NEPA"), USEPA review conducted pursuant to NEPA shall be coordinated with the broad environmental reviews under NEPA and section 309 of the CAA to the maximum extent feasible and reasonable. Under Section 309 of the CAA, USEPA is required to review and publicly comment on the environmental impacts of major Federal actions, proposed environmental regulations, and other proposed major actions. However, 40 CFR §124.9(b)(6) specifically states that PSD permits are not subject to the EIS provisions of NEPA. Therefore, DCP is not required to prepare an EIS for the PSD permit application for the proposed facility.

4.3 GHG MANDATORY REPORTING RULE

The applicability and requirements of the GHG MRR are contained in 40 CFR Part 98. The GHG MRR is applicable to facilities that meet any of the following criteria:

- 40 CFR §98.2(a)(1) – A facility that contains any source category that is listed in Table A-3 of 40 CFR Part 98, Subpart A.
- 40 CFR §98.2(a)(2) – A facility that contains any source category that is listed in Table A-4 of 40 CFR Part 98, Subpart A and emits a combined 25,000 metric tons CO_2e from stationary fuel combustion units, miscellaneous uses of carbonate, and all applicable source categories in Tables A-3 and A-4.
- 40 CFR §98.2(a)(3) – A facility that meets all three of the conditions listed below:
  - The facility is does not contain a source category listed in either Table A-3 or Table A-4 of 40 CFR Part 98, Subpart A.
  - The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is 30 MMBtu/hr or greater.
  - The facility emits 25,000 metric tons CO_2e or more per year in combined emissions from all stationary fuel combustion sources.
- 40 CFR §98.2(a)(4) – A supplier that is listed in Table A-5 of 40 CFR Part 98, Subpart A.

The GHG MRR is potentially applicable to the Hardin County NGL Fractionation Plant because it meets the following criteria:

- 40 CFR §98.2(a)(2) – The facility is listed in 40 CFR Part 98, Subpart A Table A-4, because it belongs to the Petroleum and Natural Gas Systems ("40 CFR Part 98, Subpart W") source category and will have the potential to emit 25,000 metric tons CO_2e from a combination of 40 CFR Part 98, Subpart W sources and General Stationary Fuel Combustion Sources ("40 CFR Part 98, Subpart C").
- 40 CFR §98.2(a)(4) – The facility is listed in 40 CFR Part 98, Subpart A Table A-5, because it belongs to the Natural Gas and NGL Suppliers ("40 CFR Part 98, Subpart NN") supplier category.

The Hardin County NGL Fractionation Plant will comply with the applicable requirements of the GHG MRR.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY

Under the CAA, a PSD permit must contain emissions limitations based on application of BACT for each regulated NSR pollutant. A determination of BACT for GHGs should be conducted in the same manner as it is done for any other NSR regulated pollutant.

The CAA §169(3) defines BACT as:

> *"An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant."*

Each new source at the Facility is subject to a BACT review using the USEPA "Top-Down" BACT process to determine BACT for GHGs.

Any technology selected as BACT cannot be less efficient than any technology required under a NSPS or Maximum Achievable Control Technology ("MACT") Standard. The only NSPS or MACT standard for GHG currently effective or proposed is for coal fired power plants. The Hardin County NGL Fractionation Plant is not a coal fired power plant; therefore, no applicable NSPS or MACT floors must be evaluated.

5.1 TOP-DOWN BACT PROCESS OVERVIEW

The "Top-Down" BACT review process is detailed in the draft 1990 NSR Workshop Manual. The "Top-Down" BACT review process is broken down into the following five steps.

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The first step in the Top-Down BACT review process is to identify all available control technologies, including alternative processes and practices. USEPA has divided potentially applicable control technologies to be considered during the BACT review into the following three categories[1]:

- Inherently Lower-Emitting Processes/Practices/Designs;
- Add-on Controls, and
- Combinations of Inherently Lower Emitting Processes/Practices/Designs and Add-on Controls.

GHG BACT analyses will focus primarily on lower emitting process/practices/designs through the evaluation and implementation of energy efficiency measures and practices.

Evaluation of control options should include those options applied at other source categories with exhaust streams that are similar to the source category in question. DCP has determined which control technologies are considered available using the following sources:

- The USEPA's RACT/BACT/LAER Clearinghouse;
- The USEPA's GHG Control Measures White Papers for Large Industrial/Commercial/ Institutional Boilers and Refineries;
- ENERGY STAR Industrial Sector Energy Guides and Plant Energy Performance Indicators (benchmarks); and
- Other BACT determinations for similar processes and equipment.

Although many control technologies and alternative processes may eventually be eliminated in subsequent steps, Step 1 should document all potential and relevant options.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The list of potential control technologies and strategies outlined in Step 1, as described above, is then evaluated for technical feasibility. USEPA considers technologies to be technically feasible if:

[1] USEPA's PSD and Title V Permitting Guidance for Greenhouse Gases, USEPA-457/B-11-001, March 2011.

- It has been demonstrated and operated successfully at a similar source; and
- It is available and applicable to the source under review.

USEPA does not generally consider technologies still in the pilot or research and development phases to be technically feasible due to availability.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

The control technologies considered technically feasible are then ranked according to the effectiveness. Effectiveness considers both total emissions reductions and increased energy efficiency.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

At this stage, the control technologies identified as both available and technically feasible are evaluated for environmental, economic, and energy impacts. Control technologies may be eliminated at this stage if any of the impacts are determined to be too severe.

STEP 5: SELECT BACT

The top ranked control technology determined to be technologically feasible and having acceptable environmental, economic, and energy impacts should be selected as BACT. Multiple control technologies may be selected as BACT if feasible.

5.2 BACT FOR GREENHOUSE GASES

USEPA Regulated GHGs include CO_2, CH_4, and N_2O and are expressed as CO_2e[2]. This BACT analysis will evaluate all three pollutants for each source type. Some control technologies, such as combustion control of CH_4 containing streams, will also generate other GHGs. In these cases, the control technology that produces the greatest overall reduction in CO_2e will generally be selected as BACT.

[2] HFCs, PFCs, and SF_6 are also regulated GHGs, but are not emitted by the DCP SET Frac; therefore, are not discussed.

5.3 SOURCES TO BE EVALUATED

The following sources emit GHG and will be addressed in this BACT analysis.

Table 5.3-1
Sources to be Evaluated

EPN	Source Type	Section
TRB1-1	Compression Turbine	5.3.2
TRB1-2	Compression Turbine	5.3.2
TRB1-3	Compression Turbine	5.3.2
TRB2-1	Compression Turbine	5.3.2
TRB2-2	Compression Turbine	5.3.2
TRB3-1	Compression Turbine	5.3.2
TRB3-2	Compression Turbine	5.3.2
TO1	Amine Still Vent	5.3.3
TO2	Amine Still Vent	5.3.3
TO3	Amine Still Vent	5.3.3
ENG1	Firewater Pump Engine	5.3.4
TO1	Thermal Oxidizer	5.3.5
TO2	Thermal Oxidizer	5.3.5
TO3	Thermal Oxidizer	5.3.5
HOH1-1	Hot Oil Heater	5.3.6
HOH1-2	Hot Oil Heater	5.3.6
HOH1-3	Hot Oil Heater	5.3.6
HOH2-1	Hot Oil Heater	5.3.6
HOH2-2	Hot Oil Heater	5.3.6
HOH2-3	Hot Oil Heater	5.3.6
HOH3-1	Hot Oil Heater	5.3.6
HOH3-2	Hot Oil Heater	5.3.6
HOH3-3	Hot Oil Heater	5.3.6
HTR1	Regeneration Heater	5.3.7
HTR2	Regeneration Heater	5.3.7
HTR3	Regeneration Heater	5.3.7
FUG1	Fugitives	5.3.8
FUG2	Fugitives	5.3.8
FUG3	Fugitives	5.3.8
FLR1	VOC Flare	5.3.9

5.3.1 PLANT-WIDE CONSIDERATIONS

The BACT analysis for plant wide GHG emission reductions focuses on two categories: energy efficiency measures and carbon capture and sequestration ("CCS").

5.3.1.1 ENERGY EFFICIENCY CONSIDERATION

There are several available GHG emission control strategies that will be applied on a plant wide basis. These control strategies are addressed in this section.

The plant was designed with heat and process integration in mind for increased energy efficiency. Where feasible, the plant utilizes available process streams to transfer heat or cooling which reduces combustion heating and refrigeration requirements in the process. For example, turbine waste heat recovery is utilized where technically feasible to minimize combustion heat input and process-to-process heat exchangers are used to transfer energy between process streams to reduce compression and heat duty requirements. Shell and tube heat exchangers are utilized to heat process streams which otherwise would require combustion heat sources. Shell and tube heat exchangers are also utilized to cool process streams where appropriate which reduces the refrigeration demand from the turbine compressors.

The plant will insulate equipment (vessels), piping, and components in both hot and cold service. This will prevent heat loses to the atmosphere from equipment containing hot streams or excessive warming of equipment containing cold streams. In this way, the need for additional heat input and refrigeration is minimized.

Process control instrumentation and pneumatic components will be operated using compressed air rather than fuel gas or off-gas; therefore, no GHG emissions will be emitted to the atmosphere from these components.

The plant will be built using new, state-of-the-art equipment and process instrumentation and controls. DCP's operating and maintenance policies will maintain all equipment according to manufacturer specifications in order to keep all equipment operating efficiently.

5.3.1.2 CARBON CAPTURE AND SEQUESTRATION

CCS involves four main steps:

- Capture of CO_2 from sources including combusted exhaust streams and amine still vent vapors;
- Clean-up of emission streams to remove impurities (potentially sulfur and water) to meet pipeline specifications and compress the CO_2 to pipeline conditions;
- Transport of compressed CO_2 to a sequestration site; and
- Sequestration of CO_2.

CAPTURE OF WASTE STREAMS

The potential CO_2 eligible for CCS application is summarized in Table 5.3.1-1 and includes emissions from the amine vents prior to combustion in the TOs, the turbine exhaust, and the heater exhaust. Assuming a 90% capture efficiency of CO_2, CCS would decrease CO_2 emissions by 615,718 tpy.

Table 5.3.1-1
Summary of CO_2 Emissions Available for CCS

Emission Source	Ton Per Year Reduction Per Source[1] (tpy)	Number of Sources at the Facility	Total Ton Per Year Reduction (tpy)
Turbines	24,584.39	7	172,091
Hot Oil Heaters	51,590.68	9	464,316
Regeneration Heaters	8,426.48	3	25,279
Amine Still Vents	7,481.83	3	22,445
Total			**684,131**
Total Captured (90%)			**615,718**

[1] Detailed emission rate calculations are in Section 6, Attachment B.

CLEANUP OF WASTE STREAMS

In order to remove the CO_2 from the turbine and heater exhaust streams, remove impurities from the CO_2 stream, and compress the CO_2 stream to pipeline temperature and pressure, several additions must be made to the plant. New equipment would, at a minimum, include turbines for compression of the purified CO_2 stream, heat exchangers to cool the exhaust streams from the combustion sources, additional amine units for purification of the CO_2 stream, and additional separation equipment including scrubbers and mole sieves. The additional equipment needed to purify and compress the CO_2 stream would have an estimated capital cost of $221,863,400 (see Table D-1 in Attachment D).

The annualized costs associated with the new equipment are estimated using USEPA's Air Pollution Control Cost Manual, Sixth Edition – USEPA/452/B-02-001. The direct annual operating cost of the new equipment includes factors such as operator labor to operate the equipment, routine maintenance, cost of the amine for the new amine systems, and electricity to run the new equipment. The indirect annual operating cost of the new equipment includes overheads such as administrative charges, property taxes, insurance, and the capital recovery cost of the total capital cost of the equipment. The total annualized cost of the CO_2 capture and cleanup equipment is estimated to be $52,894,660 (see Table D-2 in Section 6, Attachment D).

TRANSPORT

DCP has determined that the nearest facility capable of accepting an anthropogenic CO_2 stream is the Denbury Green Pipeline, approximately 28 miles from the Hardin County NGL Fractionation Plant (See Denbury Green Pipeline Map in Section 6, Attachment D). The capital cost of constructing the pipeline from the DCP plant to the Green Pipeline is estimated using the National Energy Technology Laboratory's document "Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs" (DOE/NETL-2010/1447, March 2010), will be approximately $17,854,713 (see Table D-3 in Section 6, Attachment D).

The annual operating costs of the pipeline are estimated using the "Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs" as referenced above. Using this methodology, the annual operating costs of the pipeline will be approximately \$241,696. In addition, the capital recovery cost is estimated using the methodology in USEPA's Air Pollution Control Cost Manual, as referenced above with a cost of approximately \$2,905,855 (see Table D-3 in Section 6, Attachment D). Therefore, the total annualized cost of the pipeline will be approximately \$3,147,551 per year:

$$C_T = C_{OC} + C_{CRC}$$
$$= \frac{\$241{,}696}{yr} + \frac{\$2{,}905{,}855}{yr}$$
$$= \$3{,}147{,}551/yr$$

Where: C_T = Total Annualized Cost (\$/yr)
C_{OC} = Total Operating Cost (\$/yr)
C_{CRC} = Total Capital Recovery Cost (\$/yr)

SEQUESTRATION

Obtaining an estimate of the cost of utilizing the Green Pipeline would require DCP to enter into a contract with Denbury. DCP does not wish to enter into a formal business agreement with Denbury; therefore, has conservatively assumed that utilizing the Denbury Green Pipeline would have a cost of \$0 per ton CO_2 sequestered. The total capital cost of implementing CCS is therefore estimated to be:

$$C_T = C_E + C_P + C_S$$
$$= \$221{,}863{,}400 + \$17{,}854{,}713 + \$0$$
$$= \$239{,}718{,}113$$

Where C_T = Total CCS Capital Cost (\$)
C_E = Total Equipment Capital Cost (\$)
C_P = Total Pipeline Capital Cost (\$)
C_S = Total Sequestration Capital Cost (\$)

Implementing CCS would increase the total capital cost of the project by 48%.

The total annualized cost of implementing CCS is estimated to be:

$$C_T = C_E + C_P + C_S$$
$$= \frac{\$52{,}894{,}660}{yr} + \frac{\$3{,}147{,}551}{yr} + \frac{\$0}{yr}$$
$$= \$56{,}042{,}211/yr$$

Where C_T = Total Annualized CCS Cost ($/yr)
C_E = Total Annualized Equipment Cost ($/yr)
C_P = Total Annualized Pipeline Cost ($/yr)
C_S = Total Annualized Sequestration Cost ($/yr)

The total annual cost per ton of CO_2 reduced would be:

$$C = \frac{C_A}{ER}$$
$$= \frac{\$56{,}042{,}211/yr}{615{,}718\ tpy}$$
$$= \$91.02/ton$$

Where C = Cost per Ton CO_2 Reduced ($/ton)
C_A = Total Annualized CCS Cost ($/yr)
ER = Ton CO_2 per Year Reduced (tpy)

DCP believes these costs to be economically unreasonable; therefore, does not propose the use of CCS as BACT.

5.3.2 TURBINES

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the information sources listed in Section 5.1 identified the following list of potential GHG control technologies for the turbines:

- CCS;
- Use of electric motors for compression;
- N_2O catalyst;
- Selection of higher energy efficient turbines;
- Use of waste heat recovery in exhaust gases;

- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Selection of low carbon fuel.

CCS

CCS would be used to capture the CO_2 from the turbine exhaust, purify, compress, and send the CO_2 via pipeline to either a storage location or another pipeline for use in enhanced oil recovery ("EOR"). CCS is discussed in detail in Section 5.3.1.2.

ELECTRIC MOTORS

The gas-fired turbines would be replaced with electric motors for compression. This would eliminate all CO_2 emissions from the gas-fired turbines at the Hardin County NGL Fractionation Plant but would result in additional energy, environmental, and economic impacts, as discussed in Step 4 of this section.

N_2O CATALYST

The use of N_2O catalyst would involve routing the turbine exhaust to an N_2O catalyst, followed by ammonia injection, and then a NO_X catalyst. This process has generally been used at nitric acid plants. Currently, manufacturers of N_2O catalyst do not provide information on catalysts for natural gas-fired turbines.

HIGHER ENERGY EFFICIENT TURBINES

Selection of higher energy efficient turbines would reduce the total heat input of the plant. Therefore emissions associated with the turbines would be reduced.

WASTE HEAT RECOVERY

The use of waste heat recovery in the turbine exhaust would increase the energy efficiency of the plant while reducing the needed heater duty in the hot oil system. Reduced heater duty in the hot oil system would result in lower emissions.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance would ensure the turbines are operating as efficiently as possible. A list of applicable good combustion practices is includes in Section 6, Attachment D. Careful control of turbine operation would also minimize CO_2 emissions. Furthermore, proper operation of the turbines would extend useful life of the turbines. DCP would also follow the manufacturer's recommended maintenance schedule to maintain proper and efficient operation of the turbines.

LOW CARBON FUELS

Selection of a lower carbon fuel would result in less CO_2 formation during combustion. Therefore, a lower carbon fuel is identified as a potential control technology.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Use of N_2O catalyst requires a concentrated N_2O stream. The exhaust stream in the turbines is too dilute to make this process technically feasible.

All remaining control technologies identified in Step 1 are considered technically feasible.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

As discussed in Section 5.3.1.2 and Step 4, both CCS and the use of electric motors have negative energy, environmental, and economic effects; therefore, are not selected as BACT. The remaining control technologies are all selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

CCS

CCS is discussed in detail in Section 5.3.1.2 and has been determined to be economically unreasonable. The discussion includes information for all CO_2 sources at the facility.

ELECTRIC MOTORS

The use of electric motors rather than gas-fired turbines for compression would have significant economic and environmental effects upon the project. From an economic standpoint, the electric motors are more expensive to operate. The gas-fired turbines each have a heat input rating of approximately 42.89 MMBtu/hr. DCP estimates the pipeline quality natural gas used to fire the turbines will cost approximately \$3/MMBtu. The total cost to operate all seven turbines is as follows:

$$C_T = HR \times N_T \times C_G \times \left(\frac{8{,}760\ \text{hrs}}{\text{yr}}\right)$$

$$= \left(\frac{42.89\ \text{MMBtu}}{\text{hr-turbine}}\right) \times (7\ \text{turbines}) \times \left(\frac{\$3}{\text{MMBtu}}\right) \times \left(\frac{8{,}760\ \text{hrs}}{\text{yr}}\right)$$

$$= \$7{,}890{,}044/\text{yr}$$

Where C_T = Total Cost to Operate all Turbines (\$/yr)
HR = Turbine Heat Input Rate (MMBtu/hr)
N_T = Total Number of Turbines
C_G = Cost of Natural Gas (\$/MMBtu)

An electric motor capable of replacing the gas-fired turbine would have a power input rating of 3.5 MW. Should DCP replace the gas turbines with electric motors, only six motors would be needed rather than seven. DCP estimates the electricity needed to power the six motors will cost approximately \$0.07/KW-hr. The total cost to operate all six motors is as follows:

$$C_T = P \times \left(\frac{1000\ \text{kW}}{\text{MW}}\right) \times N_T \times C_E \times \left(\frac{8{,}760\ \text{hrs}}{\text{yr}}\right)$$

$$= \left(\frac{3.5\ \text{MW}}{\text{Motor}}\right) \times \left(\frac{1000\ \text{kW}}{\text{MW}}\right) \times (6\ \text{Motors}) \times \left(\frac{\$0.07}{\text{kW-hr}}\right) \times \left(\frac{8{,}760\ \text{hrs}}{\text{yr}}\right)$$

$$= \$12{,}877{,}200/\text{yr}$$

Where C_T = Total Cost to Operate all Motors (\$/yr)
P = Motor Power Input Rate (MW/motor)
N_T = Total Number of Motors
C_E = Cost of Electricity (\$/kW-hr)

Installation of electric motors would also require the elimination of waste heat recovery from the turbine exhaust heat and an increased heat contribution to the process of 40 MMBtu/hr per train (total of 3 trains). The total cost to replace the waste heat recovery is as follows:

$$C_T = HR \times N_T \times C_G \times \left(\frac{8{,}760 \text{ hrs}}{\text{yr}}\right)$$
$$= \left(\frac{40 \text{ MMBtu}}{\text{hr-train}}\right) \times (3 \text{ trains}) \times \left(\frac{\$3}{\text{MMBtu}}\right) \times \left(\frac{8{,}760 \text{ hrs}}{\text{yr}}\right)$$
$$= \$3{,}153{,}600/\text{yr}$$

Where C_T = Total Cost to Replace Waste Heat Recovery ($/yr)
HR = Waste Heat Recovery Heat Input Rate (MMBtu/hr-train)
N_T = Total Number of Trains
C_G = Cost of Natural Gas ($/MMBtu)

All costs are summarized in Table 5.3.2-1.

Table 5.3.2-1
Comparison of Operating Costs Based on Energy Input

Scenario	Heat/Energy Input	Heat/Energy Cost	Increase or Decrease?	Operating Cost Per Hour	Operating Cost Per Year
7 Gas-fired Turbines	300.23 MMBtu/hr	$3/MMBtu	Decrease	($901)	($7,890,044)
6 Electric Motors	21 MW	$0.07/KW-hr	Increase	$1,470	$12,877,200
3 Trains – Increased Heater Duty	120 MMBtu/hr	$3/MMBtu	Increase	$360	$3,153,600
Net Change	**--**	**--**	**Increase**	**$929**	**$8,140,756**

As indicated in Table 5.3.2-1, the total increased cost to operate electric motors rather than gas-fired turbines would be $929/hr, or $8,140,756 per year.

Each gas-fired turbine emits 24,584 tpy CO_2 (see detailed emission rate calculations in Section 6, Attachment B). Replacing the gas-fired turbines with electric motors would decrease total CO_2 emissions as follows:

$$E_{RT} = E_R \times N_T$$
$$= \left(\frac{24{,}584 \text{ ton } CO_2}{\text{yr-turbine}}\right) \times (7 \text{ turbines})$$
$$= 172{,}088 \frac{\text{ton } CO_2}{\text{yr}}$$

Where E_{RT} = Total CO_2 Emission Reduction for All Turbines (ton/yr)
N_T = Total Number of Turbines

Removal of the waste heat recovery units in the turbines would require an increase in hot oil heater duty of approximately 40 MMBtu/hr/train. This will result in an increase in CO_2 emissions estimated as follows:

$$E_{RT} = HR \times N_T \times EF \div HV \times \left(\frac{1 \text{ ton}}{2{,}000 \text{ lbs}}\right) \times \left(\frac{8{,}760 \text{ hrs}}{\text{yr}}\right)$$
$$= \left(\frac{40 \text{ MMBtu}}{\text{hr-train}}\right) \times (3 \text{ trains}) \times \left(\frac{120{,}161 \text{ lb } CO_2}{\text{MMscf}}\right) \times$$
$$\left(\frac{\text{scf}}{918.14 \text{ Btu}}\right) \times \left(\frac{1 \text{ ton}}{2{,}000 \text{ lbs}}\right) \times \left(\frac{8{,}760 \text{ hrs}}{\text{yr}}\right)$$
$$= 68{,}787.57 \frac{\text{ton } CO_2}{\text{yr}}$$

Where E_R = Total CO_2 Emissions From Removal of Waste Heat Recovery (ton/yr)
HR = Heat Duty to Be Made up In Heaters (MMBtu/hr-train)
N_T = Total Number of Trains
EF = CO_2 Emission Factor (lb CO_2/MMscf)
HV = Heating Value of Fuel Gas (Btu/scf)

All emission changes at the plant due to replacing the gas-fired turbines with electric motors are summarized in Table 5.3.2-2.

Table 5.3.2-2
Emission Changes Due to Electrified Compression

Emission Unit	Increase or Decrease?	Change in CO_2 (tpy)
Gas-fired Turbines	Decrease	(172,088)
Hot Oil Heaters	Increase	68,788
Net Change	**Decrease**	**(103,300)**

To estimate the GHG emissions generated at the area power plants due to the power consumption of the motors, DCP obtained the fuel mix records from Entergy, the electricity provider in the area for the two year period starting in January 2010 through December 2011. The fuel mixture averages between 60% and 64% natural gas, with the balance in coal, on a rolling 12-month average based on heat input. For this analysis, DCP has conservatively assumed the fuel mix will be 64% natural gas and 36% coal at all times.

This analysis uses CO_2 emission factors from the GHG MRR for natural gas and mixed coal (Electric Power Sector) (see Table 5.3.2-3).

Table 5.3.2-3
Emission Factors for Electric Generation Based on Fuel Type

Fuel Type	Fuel Composition	Emission Factor (kg CO_2/MMBtu)[1]
Natural Gas	64%	53.02
Mixed Coal (Electric Power Sector)	36%	94.38
Mix		**67.91**

[1] 40 CFR 98, Subpart C, Table C-1.

Applying the fuel mixture percentages derived above, the total CO_2 emission factor is calculated to be 149.71 lb CO_2/MMBtu, estimated as follows:

$$EF_M = \left[(HR_{NG} \times EF_{NG}) + (HR_C \times EF_C)\right] \times \left(\frac{2.2046\text{ lb}}{\text{kg}}\right)$$

$$= \left[\left(64\% \times \frac{53.02\text{ kg CO2}}{\text{MMBtu}}\right) + \left(36\% \times \frac{94.38\text{ kg CO2}}{\text{MMBtu}}\right)\right] \times \left(\frac{2.2046\text{ lb}}{\text{kg}}\right)$$

$$= 149.71\ \frac{\text{lb } CO_2}{\text{MMBtu}}$$

Where EF_M = Total CO_2 Emission Factor for Fuel Mix (lb CO_2/MMBtu)
HR_{NG} = Percentage Natural Gas in Fuel Mix
EF_{NG} = Total CO_2 Emission Factor for Natural Gas (lb CO_2/MMBtu)
HR_C = Percentage Coal in Fuel Mix
EF_C = Total CO_2 Emission Factor for Coal (lb CO_2/MMBtu)

To simplify the analysis, DCP has assumed all power plants in the area have the same heat rate as a new natural gas-fired combined cycle turbine, or 7,000 Btu/KW-hr[3]. This assumption is conservatively low and does not account for the lower thermal efficiency operation of the coal-fired power plants, natural gas power plants with a lower thermal efficiency than the one assumed in this analysis, or the increased firing rates at the power plants needed to compensate for transmission losses.

Replacing the seven gas-fired turbines would require six electric motors with an energy consumption of 3.5 MW each, or 21 MW total. The total heat input at the area power plants due to the use of electric motors is calculated as follows:

$$\left(\frac{21\text{ MW}}{\text{hr}}\right) \times \left(\frac{1{,}000\text{ kW}}{1\text{ MW}}\right) \times \left(\frac{7{,}000\text{ Btu}}{\text{kW-hr}}\right) \times \left(\frac{1\text{ MMBtu}}{10^6\text{ Btu}}\right) = 147\ \frac{\text{MMBtu}}{\text{hr}}$$

The total increases in annual CO_2 emissions at the area power plants due to the use of electric motors are calculated as follows:

$$\left(\frac{147\text{ MMBtu}}{\text{hr}}\right) \times \left(\frac{149.71\text{ lb } CO_2}{\text{MMBtu}}\right) \times \left(\frac{8{,}760\text{ hrs}}{\text{yr}}\right) \times \left(\frac{1\text{ ton}}{2{,}000\text{ lb}}\right) = 96{,}392\text{ tpy } CO_2$$

Table 5.3.2-4
Comparison of Emission Changes Due to Electrified Turbines

Emission Source	Increase or Decrease?	Change in CO_2 (tpy)
Hardin County NGL Fractionation Plant	Decrease	(103,300)
Area Power Plants	Increase	96,392
Net Change	**Decrease**	**(6,908)**

The net CO_2 emission change is a decrease of 6,908 tpy CO_2. Table summarizes the potential net emission change due to the use of electric motors.

[3] The application for the Lower Colorado River Authority Ferguson Plant, submitted March 2011 and final permit issued November 10, 2011, included a BACT net average net heat rate of 7,720 Btu/kW-hr. The heat rate used in this BACT analysis is more efficient than that of the newly permitted LCRA Ferguson Plant.

The cost per ton reduction of CO_2 is estimated as follows:

$$\frac{\$8,140,756}{6,908 \text{ tpy } CO_2} = \frac{\$1,178}{\text{ton } CO_2}$$

DCP does not believe electric motors to be economically reasonable.

HIGHER ENERGY EFFICIENT TURBINES

Selection of a higher energy efficient turbine would reduce the total heat input into the plant and the emissions associated with the turbines. The turbines selected for use at the plant are Solar Centaur turbines that operate with 28% thermal efficiency and have a power rating of 4,700 brake horsepower ("bhp"). They were selected as the only turbines with the appropriate power rating and reliability needed for the plant.

DCP has identified only one other turbine with a power input rating within 100% of the Solar Turbines. The Siemens SGT-100 Industrial Gas Turbine (specification sheet is included in Attachment D) operates with 33% thermal efficiency and has a power rating of 7,640 bhp, 63% greater than the Solar turbines selected. Although the Siemens turbines are more efficient, to maintain operational flexibility, DCP requests to install two turbines per train. Installation of 2 turbines per train would increase the turbine CO_2e emissions up to 18,607 tpy or 63%, per turbine[4]. The CO_2 emission rate is estimated as follows:

[4] Detailed emission rate calculations for the Solar turbines are included in Section 6, Attachment B.

$$ER_{ST} = \left(\frac{HP_{ST}}{HP_T}\right) \times ER_T$$

$$= \left(\frac{7{,}640 \text{ hp}}{4{,}700 \text{ hp}}\right) \times 24{,}584 \text{ tpy}$$

$$= 39{,}962 \text{ tpy}$$

Where ER_{ST} = Emission Rate of Alternative Turbine (tpy CO_2e)
HP_{ST} = Horsepower Rating of Alternative Turbine (hp)
HP_T = Horsepower Rating of Current Turbine (hp)
ER_T = Emission Rate of Current Turbine (tpy CO_2e)

$$\% \text{ Increase} = \frac{ER_{ST}}{ER_T} \text{ x } 100\%$$

$$= \frac{39{,}962 \text{ tpy}}{24{,}584 \text{ tpy}} \text{ x } 100\%$$

$$= 163\%$$

Due to the negative environmental effects of selecting a different turbine, DCP proposes the Solar Centaur turbines as BACT.

WASTE HEAT RECOVERY

The use of waste heat recovery of the turbine exhaust increases the energy efficiency of the plant while reducing the needed heater duty per train by 40 MMBtu/yr. As shown in Table 5.3.2-2, this corresponds to a decrease in CO_2 emissions of 68,788 tpy. DCP has already chosen to implement waste heat recovery and has therefore not evaluated the cost of implementation separately from the overall project cost.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance would ensure the turbines are operating as efficiently as possible. Furthermore, proper operation of the turbines would extend their useful life and have a positive environmental and energy conservation effects.

LOW CARBON FUELS

The proposed turbines will burn pipeline quality natural gas which has the lowest carbon content of available fuels. No lower carbon content fuels have been identified.

STEP 5: SELECT BACT

BACT for the turbines is selected as follows:

- Use of energy efficient turbines;
- Waste heat recovery;
- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Selection of low carbon fuel.

HIGHER ENERGY EFFICIENT TURBINES

As discussed in Step 4, the Solar Centaur turbines selected for use at the plant are the most efficient turbines available for the refrigeration process. Therefore, these turbines are selected as BACTs for energy efficiency.

WASTE HEAT RECOVERY

The plant design includes the use of waste heat recovery in the turbine exhaust. The heat recovered will be used in the hot oil system to carry heat to other parts of the plant. Use of waste heat recovery will decrease the necessary heater duty by 40 MMBtu/hr per train.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The plant design includes specifications for state of the art process instrumentation and controls. A list of applicable good combustion practices is included in Section 6, Attachment D. DCP will follow the recommended maintenance from the turbine manufacturer.

LOW CARBON FUELS

The proposed turbines will burn pipeline quality natural gas which has the lowest carbon content of available fuels; no lower carbon fuels have been identified. Therefore, the use of natural gas will result in the lowest CO_2 emissions from the turbines.

DCP proposes the following emission limitations and monitoring for the turbines:

Table 5.3.2-5
Turbine CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (tpy CO_2e)	Time Period	Monitoring Proposal
TRB1-1	24,609.55	Annual	Fuel Consumption
TRB1-2	24,609.55	Annual	Fuel Consumption
TRB2-1	24,609.55	Annual	Fuel Consumption
TRB2-2	24,609.55	Annual	Fuel Consumption
TRB2-3	24,609.55	Annual	Fuel Consumption
TRB3-1	24,609.55	Annual	Fuel Consumption
TRB3-2	24,609.55	Annual	Fuel Consumption

5.3.3 AMINE STILL VENT GASES

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the sources listed in Section 5.1 identified the following list of potential GHG control technologies for the amine still vent gases:

- CCS;
- Routing amine still vent gases to a control device; and
- Selection of an amine with low regeneration heating requirements.

CCS

CCS would be used to capture the CO_2 from the amine still vent gases, purify, compress, and send the CO_2 via pipeline to either a storage location or another pipeline for use in EOR. CCS is discussed in detail in Section 5.3.1.2.

ROUTING VENT GASES TO CONTROL

Routing the amine still vent gases to a control device would decrease the CH_4 emissions due to the amine system by the applicable destruction efficiency. At the plant, the two available control devices are the facility flare with a DRE of 98% and the TO with a DRE of 99.9%. However, destruction of the CH_4 will result in the creation of CO_2.

SELECTION OF AMINE

The selection of the amine solution for use in the amine unit determines the amount of heat needed to regenerate the amine. Therefore, this directly effects CO_2 emissions from the hot oil system.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

All control technologies identified in Step 1 are considered technically feasible. Therefore, each control technology is considered in Step 3.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

As discussed in Section 5.3.1.2, CCS has negative energy, environmental, and economic effects; therefore, is not selected as BACT. The remaining control technologies are selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

CCS

CCS is discussed in detail in Section 5.3.1.2 and has been determined to be economically unreasonable. The discussion includes information for all CO_2 sources at the facility.

ROUTING VENT GASES TO CONTROL

Routing the amine still vent gases to either control device is assumed to have no energy and economic impacts. However, the destruction of CH_4 will form a stoichiometrically equivalent amount of CO_2. As discussed in Section 3.2, CO_2 has a lower GWP than CH_4. Therefore, routing the amine still vent gases to control will decrease the total CO_2e emissions associated with the amine still vent gases.

AMINE SELECTION

Use of an amine solution with a low regeneration heat requirement lowers operational expenses, heat load, and GHG emission rates. However, proper operation of the plant requires an inlet gas stream with as little CO_2 as possible. Therefore, a low regeneration heat amine is desirable.

STEP 5: SELECT BACT

BACT for the amine vent still gases has been selected as follows:

- Routing the amine vent to the TO; and
- Use of an amine with low regeneration heating requirements.

ROUTING VENT GASES TO CONTROL

The amine still vent gases from each train will be routed to the corresponding TO. As stated in Step 4, this technology results in lower CH_4 emissions which have a higher GWP than CO_2.

AMINE SELECTION

The amine unit will utilize UCARSOL, which has a low heat regeneration requirement. Due to the heat regeneration requirement, less CO_2 will be emitted from combustion sources generating the heat in the plant hot oil system.

As discussed above, BACT for the amine still vent includes combustion control in a TO. Therefore, the emission limitation proposed is only for the combustion of the amine still vent gas in the TOs. The emission limitations from the combustion of fuel gas in the TO are discussed in Section 5.3.7.

Table 5.3.3-1
Amine Still Vent Gases CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (lb CO_2e/hr)	Time Period	Monitoring Proposal
TO1	17,086.63	Annual And Rolling 12-month Total	Maximum Annual Waste Stream Volume Processed
TO2	17,086.63	Annual And Rolling 12-month Total	Maximum Annual Waste Stream Volume Processed
TO3	17,086.63	Annual And Rolling 12-month Total	Maximum Annual Waste Stream Volume Processed

5.3.4 EMERGENCY FIREWATER PUMP ENGINE

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the sources listed in Section 5.1 identified the following list of potential GHG control technologies for the firewater pump engine:

- CCS;
- Selection of efficient engines;
- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Use of low carbon fuel.

CCS

CCS would be used to capture the CO_2 from the engine exhaust, purify, compress, and send the CO_2 via pipeline to either a storage location or another pipeline for use in EOR. CCS is discussed in detail in Section 5.3.1.2.

ENERGY EFFICIENT ENGINES

Selection of an energy efficient engine would reduce the total heat input of the plant and the emissions associated with the engine. Therefore, an energy efficient engine is identified as a potential control technology.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance would ensure the engine is operating as efficiently as possible. Careful control of engine operation would also minimize CO_2 emissions. Further, proper operation of the engine would extend its useful life. DCP would also follow the manufacturer's recommended maintenance schedule to maintain proper and efficient operation of the engine.

LOW CARBON FUELS

Selection of a lower carbon fuel, such as natural gas, would result in less CO_2 formation during combustion. Therefore, a lower carbon fuel is identified as a potential control technology.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

CCS

CCS requires a continuous exhaust stream to be considered technically feasible. As the firewater pump engine will only be operated intermittently, the exhaust from the engine is not a good candidate for CCS. Therefore, DCP wishes to eliminate CCS from further consideration for the firewater pump engine.

LOW CARBON FUELS

The engine will fire diesel stored on-site in a storage tank. An engine firing natural gas may be more efficient, as natural gas is the fuel with the lowest carbon content. However, the engine is required to be available for use at any time, including when the plant will not be supplied with natural gas. To meet this need and minimize fuel storage costs, DCP has selected a diesel-fired pump engine for its reliability and availability during an emergency.

Both remaining control technologies are considered technically feasible. Therefore, these control technologies are considered in Step 3.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

As discussed in Section 5.3.1.2 and Step 2, CCS and the use of natural gas are considered technically infeasible. The remaining control technologies are selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

ENERGY EFFICIENT ENGINES

The engines are required to be available for use at any time in the unlikely event of an emergency. To meet this need, DCP has selected diesel-fired pump engines for their reliability and availability.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance will ensure the engines are operating as efficiently as possible. Further, proper operation of the engines will extend the useful life of the engine and have positive environmental and energy conservation effects.

STEP 5: SELECT BACT

DCP proposes the use of the following technologies as BACT:

- Selection of efficient firewater pump engine; and
- Use of good combustion practices.

ENERGY EFFICIENT ENGINES

The selected engine is required to be available for use at any time in the event of an emergency, including when natural gas is not available. A diesel-fired pump engines has been selected for its availability, reliability, and minimum fuel storage requirements.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The Plant design includes specifications for state of the art process instrumentation and controls. A list of applicable good combustion practices is included in Section 6, Attachment D. DCP will follow the recommended maintenance from the engine manufacturer.

DCP proposes the following emission limitations and monitoring for the engine:

Table 5.3.4-1
Firewater Pump Engine CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (ton CO_2e/yr)	Time Period	Monitoring Proposal
ENG1	76.03	Monthly	Hours of Operation

5.3.5 THERMAL OXIDIZERS

The TO are used to control waste gas streams from the amine vent and other process streams. This section addresses BACT for the TO and routine burning of fuel gas only. BACT for the waste streams controlled by the TO are addressed in Section 5.3.3.

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the sources listed in Section 5.1 identified the following list of potential GHG control technologies for the TOs:

- CCS;
- Use of a regenerative TO;
- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Selection of low carbon fuel.

CCS

CCS would be used to capture the CO_2 from the TO exhaust, purify, compress, and send the CO_2 via pipeline to either a storage location or another pipeline for use in EOR. CCS is discussed in detail in Section 5.3.1.2.

REGENERATIVE THERMAL OXIDIZER

The use of regenerative thermal oxidizers ("RTO") would allow the plant to recover heat from the exhaust stream, reducing the overall heat input of the plant. This option would decrease the emissions from the plant due to less fuel combustion required to generate heat.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance would ensure the TO are operating as efficiently as possible. Careful control of TO operation would also minimize CO_2 emissions. Furthermore, proper operation of the TO would extend their useful life. DCP would also follow the manufacturer's recommended maintenance schedule to maintain proper and efficient operation of the TOs.

LOW CARBON FUELS

Selection of a lower carbon fuel would result in less CO_2 formed during combustion. Therefore, a lower carbon fuel is identified as a potential control technology.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The use of an RTO is considered technically infeasible. Use of an RTO requires a waste stream with a very low heating value (less than 50 Btu/scf). The waste gases from the process streams to be controlled have a much higher heating value (approximately 1,000 Btu/scf). Use of an RTO to burn a stream with a HHV could lead to the TO overheating, creating an unsafe situation. Therefore, DCP has eliminated the use of an RTO from this BACT analysis. The remaining control technologies identified in Step 1 are considered technically feasible.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

As discussed in Section 5.3.1.2, CCS has negative energy, environmental, and economic effects; therefore, is not selected as BACT. The remaining control technologies are all selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

CCS

CCS is discussed in detail in Section 5.3.1.2 and has been determined to be economically unreasonable. This discussion includes information for all CO_2 sources at the facility.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance would ensure the TO are operating as efficiently as possible. Further, proper operation of the TO will extend their useful life and have only positive environmental and energy effects.

LOW CARBON FUELS

The proposed TO will burn pipeline quality natural gas which has the lowest carbon content of available fuels. No lower carbon content fuels have been identified. Therefore, the use of natural gas will result in the lowest CO_2 emissions from the TO.

STEP 5: SELECT BACT

BACT for the TO has been selected as follows:

- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Selection of low carbon fuel.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The plant design includes specifications for state of the art process instrumentation and controls. A list of applicable good combustion practices is included in Section 6, Attachment D. DCP will follow the recommended maintenance schedule from the TO manufacturer.

LOW CARBON FUELS

The proposed TO will burn pipeline quality natural gas which has the lowest carbon content of available fuels. No lower carbon content fuels have been identified.

DCP proposes the following emission limitations and monitoring for the TO from the burning of fuel gas only:

Table 5.3.5-1
TO CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (ton CO_2e/yr)	Time Period	Monitoring Proposal
TO1	4,733.83	Annual	Weekly Fuel Gas Consumption
TO2	4,733.83	Annual	Weekly Fuel Gas Consumption
TO3	4,733.83	Annual	Weekly Fuel Gas Consumption

5.3.6 HOT OIL HEATERS

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the sources listed in Section 5.1 identified the following list of potential GHG control technologies for the hot oil heaters:

- CCS;
- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Selection of low carbon fuel.

CCS

CCS would be used to capture the CO_2 from the hot oil heater exhaust, purify it, compress it, and send the CO_2 via pipeline to either a storage location or another pipeline for use in EOR. CCS is discussed in detail in Section 5.3.1.2.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance would ensure the hot oil heaters are operating as efficiently as possible. Careful control of hot oil heater operation would also minimize CO_2 emissions. Furthermore, proper operation of the hot oil heaters would extend their useful life. DCP would also follow the manufacturer's recommended maintenance schedule to maintain proper and efficient operation of the hot oil heaters.

LOW CARBON FUELS

Selection of a lower carbon fuel would result in less CO_2 formation during combustion. Therefore, a lower carbon fuel is identified as a potential control technology.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The control technologies identified in Step 1 are considered technically feasible. Therefore, each control technology is considered in Step 3.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

As discussed in Section 5.3.1.2, CCS has negative energy, environmental, and economic effects; therefore, is not selected as BACT. The remaining control technologies are all selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

CCS

CCS is discussed in detail in Section 5.3.1.2 and has been determined to be economically unreasonable. This discussion includes information for all CO_2 sources at the facility.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance would ensure the hot oil heaters are operating as efficiently as possible. Furthermore, proper operation of the hot oil heaters will extend their useful life and have only positive environmental and energy effects.

LOW CARBON FUELS

The proposed hot oil heaters will burn pipeline quality natural gas which has the lowest carbon content of available fuels. No lower carbon content fuels have been identified.

STEP 5: SELECT BACT

BACT for the hot oil heaters has been selected as follows:

- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Selection of low carbon fuel.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The plant design includes specifications for state of the art process instrumentation and controls. A list of applicable good combustion practices is included in Section 6, Attachment D. DCP will follow the recommended maintenance schedule from the hot oil heater manufacturer.

LOW CARBON FUELS

The proposed hot oil heaters will burn pipeline quality natural gas which has the lowest carbon content of available fuels. No lower carbon content fuels have been identified. Therefore, the use of natural gas will result in the lowest CO_2 emissions from the hot oil heaters

DCP proposes the following emission limitations and monitoring for the hot oil heaters:

Table 5.3.6-1
Hot Oil Heater CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (ton CO_2e/yr)	Time Period	Monitoring Proposal
HOH1-1	51,642.05	Annual	Weekly Fuel Gas Consumption
HOH1-2	51,642.05	Annual	Weekly Fuel Gas Consumption
HOH1-3	51,642.05	Annual	Weekly Fuel Gas Consumption
HOH2-1	51,642.05	Annual	Weekly Fuel Gas Consumption
HOH2-2	51,642.05	Annual	Weekly Fuel Gas Consumption
HOH2-3	51,642.05	Annual	Weekly Fuel Gas Consumption
HOH3-1	51,642.05	Annual	Weekly Fuel Gas Consumption
HOH3-2	51,642.05	Annual	Weekly Fuel Gas Consumption
HOH3-3	51,642.05	Annual	Weekly Fuel Gas Consumption

5.3.7 REGENERATION HEATERS

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the sources listed in Section 5.1 identified the following list of potential GHG control technologies for the regeneration heaters:

- CCS;
- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Selection of low carbon fuel.

CCS

CCS would be used to capture the CO_2 from the regeneration heater exhaust, purify, compress, and send the CO_2 via pipeline to either a storage location or another pipeline for use in EOR. CCS is discussed in detail in Section 5.3.1.2.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance would ensure the regeneration heaters are operating as efficiently as possible. Careful control of regeneration heater operation would also minimize CO_2 emissions. Furthermore, proper operation of the regeneration heaters would extend their useful life. DCP would also follow the manufacturer's recommended maintenance schedule to maintain proper and efficient operation of the regeneration heaters.

LOW CARBON FUELS

Selection of a lower carbon fuel would result in less CO_2 formation during combustion. Therefore, a lower carbon fuel is identified as a potential control technology.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Both control technologies identified in Step 1 are considered technically feasible. Therefore, each control technology is considered in Step 3.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

As discussed in Section 5.3.1.2, CCS has negative energy, environmental, and economic effects; therefore, is not selected as BACT. Both remaining control technologies are all selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

CCS

CCS is discussed in detail in Section 5.3.1.2 and has been determined to be economically unreasonable. This discussion includes information for all CO_2 sources at the facility.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The use of efficient process controls, good combustion practices, and scheduled maintenance would ensure the regeneration heaters are operating as efficiently as possible. Furthermore, proper operation of the regeneration heaters will extend their useful life and have only positive environmental and energy effects.

LOW CARBON FUELS

The proposed regeneration heaters will burn pipeline quality natural gas which has the lowest carbon content of available fuels. No lower carbon content fuels have been identified.

STEP 5: SELECT BACT

BACT for the regeneration heaters has been selected as follows:

- Use of efficient process controls, good combustion practices, and scheduled maintenance; and
- Selection of low carbon fuel.

PROCESS CONTROLS, GOOD COMBUSTION PRACTICES, MAINTENANCE

The Plant design includes specifications for state of the art process instrumentation and controls. A list of applicable good combustion practices is included in Section 6, Attachment D. DCP will follow the recommended maintenance schedule from the regeneration heater manufacturer.

LOW CARBON FUELS

The proposed regeneration heaters will burn pipeline quality natural gas which has the lowest carbon content of available fuels. No lower carbon content fuels have been identified.

DCP proposes the following emission limitations and monitoring for the regeneration heaters:

Table 5.3.7-1
Regeneration Heater CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (ton CO_2e/yr)	Time Period	Monitoring Proposal
HTR1	8,426.48	Annual	Weekly Fuel Gas Consumption
HTR2	8,426.48	Annual	Weekly Fuel Gas Consumption
HTR3	8,426.48	Annual	Weekly Fuel Gas Consumption

5.3.8 PLANT FUGITIVES

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the sources listed in Section 5.1 identified the following list of potential GHG control technologies for the fugitives:

- Leakless component designs; and
- Leak detection and repair program.

LEAKLESS DESIGN

The use of leakless fugitive components would involve installing pumps designed to be leakless, welded flanges, and otherwise sealing potential sources of fugitive emissions. Therefore, leakless design is identified as a potential control technology.

LEAK DETECTION AND REPAIR PROGRAM

The implementation of a leak detection and repair program will ensure any potential emissions, due to leaking components, are promptly identified and repaired. Therefore, a leak detection and repair program is identified as a potential control technology.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Both control technologies identified in Step 1 are considered technically feasible. Therefore, each control technology is considered in Step 3.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

Both control technologies identified in Step 1 are selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

Both control technologies identified in Step 1 have the potential to reduce GHG emissions by up to 100%. Therefore, both control technologies have positive environmental impacts.

STEP 5: SELECT BACT

BACT for the fugitives has been selected as follows:

- Leakless component designs; and
- Leak detection and repair program.

LEAKLESS DESIGN

DCP will use leakless fugitive components, where economical and safe, to eliminate potential sources of fugitive emissions. Examples of leakless fugitive component designs available for use at the plant are listed in TCEQ's Guidance Document for Equipment Leak Fugitives, Page 17, in Section 6, Attachment D.

LEAK DETECTION AND REPAIR PROGRAM

DCP will implement a leak detection and repair program utilizing instrument monitors and a leak definition of 10,000 parts per million by volume that will control most fugitive equipment leaks by up to 97%. The leak detection and repair program utilized is defined by TCEQ as their "28M" program and is detailed in TCEQ's Guidance Document for Equipment Leak Fugitives, Page 13, in Section 6, Attachment D.

DCP proposes the following emission limitations and monitoring for fugitives:

Table 5.3.8-1
Fugitive CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (tons CO_2e/yr)	Time Period	Monitoring Proposal
FUG1	120.75	Annual	Quarterly with Instrument Monitor
FUG2	120.75	Annual	Quarterly with Instrument Monitor
FUG3	120.75	Annual	Quarterly with Instrument Monitor

5.3.9 FLARE

The plant flare is used to safely dispose of emergency releases of hydrocarbon and MSS events from three trains. Use of a flare minimizes CO_2 emissions by converting CH_4 with a GWP of 21 to CO_2 with a GWP of 1.

STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The review of the sources listed in Section 5.1 identified the following list of potential GHG control technologies for the flare:

- CCS;
- Minimization of releases sent to flare; and
- Use of low carbon fuel for pilot and sweep gas.

CCS

CCS would be used to capture the CO_2 from the flare, purify, compress, and send the CO_2 via pipeline to either a storage location or another pipeline for use in EOR. CCS is discussed in detail in Section 5.3.1.2.

MINIMIZATION OF RELEASES

Minimization of emergency and MSS releases sent to the flare would minimize GHG emissions from the flare. Therefore, minimization of releases to the flare is identified as a potential control technology.

LOW CARBON FUELS

Selection of a lower carbon fuel would result in less CO_2 formed during combustion. Therefore a lower carbon furl is identified as a potential control technology.

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

CCS

Currently, capture and control of post-combustion CO_2 from the flare is technologically infeasible due to the height and heat content the flare. Therefore, CCS for GHG from the flare is infeasible. Both remaining control technologies identified in Step 1 are considered technically feasible.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

Both remaining control technologies are all selected as BACT. Therefore, no ranking is necessary.

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

MINIMIZATION OF RELEASES

Minimization of emergency and MSS releases sent to the flare would minimize GHG emissions from the flare. Therefore, minimizing releases to the flare is identified as an effective control technology.

LOW CARBON FUELS

Selection of a low carbon fuel, such as natural gas, would result in less CO_2 formation during combustion. Therefore, a low carbon fuel is identified as an effective control technology.

STEP 5: SELECT BACT

BACT for the flare has been selected as follows:

- Minimization of releases sent to flare; and
- Use of natural gas for pilot and sweep gas.

MINIMIZATION OF RELEASES

DCP will operate the plant in such a way as to minimize release streams sent to the flare. This method of operation will result in less GHG emissions from the flare.

LOW CARBON FUELS

The proposed flare will burn pipeline quality natural gas which has the lowest carbon content of available fuels; no lower carbon fuels have been identified.

DCP proposes the following emission limitations and monitoring for flare:

Table 5.3.9-1
Flare CO_2e BACT Emission Limitations and Monitoring Proposal

EPN	Emission Limit (tpy)	Time Period	Monitoring Proposal
FLR1	448.40	Annual	Volume of fuel gas and waste gas volume.

6.0 ATTACHMENTS

The following information is included in this section:

- Attachment A – TCEQ Forms and Tables
- Attachment B – Detailed GHG Emission Estimates
- Attachment C – Support Documentation
- Attachment D – Supporting BACT Information

ATTACHMENT A

TCEQ FORMS AND TABLES

PI-1

Table 1(a)

Table 4 – Combustion Units

Table 6 – Boilers and Heaters

Table 7(a) – Vertical Fixed Roof Storage Tanks

Table 7 (b) – Horizontal Fixed Roof Storage Tanks

Table 8 – Flares

Table 29 – Reciprocating Engines

Table 31 – Combustion Turbines

Form PI-1

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

TCEQ

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: DCP Midstream, LP		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name: Lynn C. Ward		
Title: Senior Environmental Specialist		
Mailing Address: 662 S. Shelby		
City: Carthage	State: TX	ZIP Code: 75633
Telephone No.: 903-694-4114	Fax No.: 902-690-0041	E-mail Address: lcward@dcpmidstream.com
C. Technical Contact Name: Lynn C. Ward		
Title: Senior Environmental Specialist		
Company Name: DCP Midstream, LP		
Mailing Address: 662 S. Shelby		
City: Carthage	State: TX	ZIP Code: 75633
Telephone No.: 903-694-4114	Fax No.: 432-620-4162	E-mail Address: lcward@dcpmidstream.com
D. Site Name: Hardin County NGL Fractionation Plant		
E. Area Name/Type of Facility: Hardin County NGL Fractionation Plant		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Natural Gas Liquids		
Principal Standard Industrial Classification Code (SIC): 1321		
Principal North American Industry Classification System (NAICS): 211112		
G. Projected Start of Construction Date: June 2013		
Projected Start of Operation Date: January 2015		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: See Area Map		
City/Town:	County:	ZIP Code:
Latitude (nearest second): 3461953	Longitude (nearest second): 3336268	

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

I.	**Applicant Information (continued)**	
I.	Account Identification Number (leave blank if new site or facility):	
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):	
L.	Regulated Entity Number (RN):	
II.	**General Information**	
A.	Is confidential information submitted with this application? If *Yes*, mark each **confidential** page **confidential** in large red letters at the bottom of each page.	☐ YES ☒ NO
B.	Is this application in response to an investigation or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	☐ YES ☒ NO
C.	Number of New Jobs: estimated 75	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
	Senator: Tommy Williams	District No.: 4
	Representative: John C. Otto	District No.: 18
III.	**Type of Permit Action Requested**	
A.	Mark the appropriate box indicating what type of action is requested. Initial ☒ Amendment ☐ Revision (30 TAC 116.116(e)) ☐ Change of Location ☐ Relocation ☐	
B.	Permit Number (if existing):	
C.	Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* Construction ☒ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Prevention of Significant Deterioration ☒ Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐ Other:____________________	
D.	Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c)	☐ YES ☒ NO

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

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

III. Type of Permit Action Requested (continued)		
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*		
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. (check all that apply)		
GOP Issued ☐	GOP application/revision application submitted or under APD review ☐	
SOP Issued ☐	SOP application/revision application submitted or under APD review ☐	
IV. Public Notice Applicability		
A. Is this a new permit application or a change of location application?		☒ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.		☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?		☐ YES ☒ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?		☐ YES ☒ NO
If *Yes*, list the affected state(s) and/or Class I Area(s).		
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E 3.		
1. Is there any change in character of emissions in this application?		☐ YES ☐ NO
2. Is there a new air contaminant in this application?		☐ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?		☐ YES ☐ NO
F. List the total annual emission increases associated with the application (*list* **all** *that apply and attach additional sheets as needed*):		
Volatile Organic Compounds (VOC):		
Sulfur Dioxide (SO_2):		
Carbon Monoxide (CO):		
Nitrogen Oxides (NO_x):		
Particulate Matter (PM):		
PM $_{10}$ microns or less (PM_{10}):		
PM $_{2.5}$ microns or less ($PM_{2.5}$):		
Lead (Pb):		
Hazardous Air Pollutants (HAPs):		
Other speciated air contaminants **not** listed above	Carbon Dioxide Equivalent (CO2e): 749,958	

V. Public Notice Information (complete if applicable)		
A. Public Notice Contact Name Lynn Ward		
Title: Senior Environmental Specialist		
Mailing Address: 662 S. Shelby		
City: Carthage	State: TX	ZIP Code: 75633
Telephone No.: 903-694-4114		
B. Name of the Public Place: Alma M. Carpenter Library		
Physical Address (No P.O. Boxes): 300 South Ann St		
City: Sour Lake	County: Hardin	ZIP Code: 77659
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: Billy Caraway		
Mailing Address: 300 Monroe Street		
City: Kountze,	State: TX	ZIP Code: 77625
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? *(For Concrete Batch Plants)*	☐ YES ☐ NO	
Presiding Officers Name(s)		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executive of the city for the location where the facility is or will be located.		
Chief Executive: Bruce Robinson, Mayor of Sour Lake		
Mailing Address: 625 Hwy 105 W.		
City: Sour Lake	State: TX	ZIP Code: 77659

V. Public Notice Information (complete if applicable) (continued)	
3. Provide the name, mailing address of the Indian Governing Body for the location where the facility is or will be located. *(continued)*	
Name of the Indian Governing Body	
Title:	
Mailing Address:	
City: State: ZIP Code:	
D. Bilingual Notice	
Is a bilingual program **required** by the Texas Education Code in the School District?	☒ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?	☒ YES ☐ NO
If *Yes*, list which languages are required by the bilingual program? 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 ☒	

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

VII. Technical Information			
B. Are any schools located within 3,000 feet of this facility?			☐ YES ☒ NO
C. Maximum Operating Schedule:			
Hours: 24	Day(s): 365	Week(s): 52	Year(s): 8,760 hrs
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.			
N/A - New Facility			
E. Does this application involve any air contaminants for which a *disaster review* is required?			☐ YES ☒ NO
F. Does this application include a pollutant of concern on the *Air Pollutant Watch List (APWL)*?			☐ YES ☒ NO
VIII. State Regulatory Requirements **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment**. *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*			
A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?			☒ YES ☐ NO
B. Will emissions of significant air contaminants from the facility be measured?			☒ YES ☐ NO
C. Is the Best Available Control Technology (BACT) demonstration attached?			☒ YES ☐ NO
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?			☒ YES ☐ NO
IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*			
A. Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?			☒ YES ☐ NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?			☐ YES ☒ NO
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?			☒ YES ☐ NO

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

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** ***The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.***	
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	

Is the estimated capital cost of the project greater than $2 million dollars?	☒ YES ☐ NO
If *Yes*, submit the application under the seal of a Texas licensed P.E.	
XI. Permit Fee Information	
Check, Money Order, Transaction Number ,ePay Voucher Number:	Fee Amount: $
Company name on check:	Paid online?: ☐ YES ☐ NO
Is a copy of the check or money order attached to the original submittal of this application?	☐ YES ☐ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☐ YES ☐ NO ☐ N/A

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

TCEQ

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: Lynn Ward
Signature: Lynn Ward *Original Signature Required*
Date: 5/23/2012

Table 1(a)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	22-May-12	Permit No.:		Regulated Entity No.:	
Area Name:	Hardin County NGL Fractionation Plant			Customer Reference No.:	CN601229917

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND	(B) TPY
TRB1-1	TRB1-1	4700 hp Solar Centaur T4	CO_2e	5,618.28	24,609.55
TRB1-2	TRB1-2	4700 hp Solar Centaur T4	CO_2e	5,618.28	24,609.55
TRB1-3	TRB1-3	4700 hp Solar Centaur T4	CO_2e	5,618.28	24,609.55
TRB2-1	TRB2-1	4700 hp Solar Centaur T4	CO_2e	5,618.28	24,609.55
TRB2-2	TRB2-2	4700 hp Solar Centaur T4	CO_2e	5,618.28	24,609.55
TRB3-1	TRB3-1	4700 hp Solar Centaur T4	CO_2e	5,618.28	24,609.55
TRB3-2	TRB3-2	4700 hp Solar Centaur T4	CO_2e	5,618.28	24,609.55
HOH1-1	HOH1-1	Hot Oil Heater 1-1	CO_2e	11,789.51	51,642.05
HOH1-2	HOH1-2	Hot Oil Heater 1-2	CO_2e	11,789.51	51,642.05
HOH1-3	HOH1-3	Hot Oil Heater 1-3	CO_2e	11,789.51	51,642.05
HOH2-1	HOH2-1	Hot Oil Heater 2-1	CO_2e	11,789.51	51,642.05
HOH2-2	HOH2-2	Hot Oil Heater 2-2	CO_2e	11,789.51	51,642.05
HOH2-3	HOH2-3	Hot Oil Heater 2-3	CO_2e	11,789.51	51,642.05

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	22-May-12	**Permit No.:**		**Regulated Entity No.:**	
Area Name:	Hardin County NGL Fractionation Plant			**Customer Reference No.:**	CN601229917

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

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) POUND**	**(B) TPY**
HOH3-1	HOH3-1	Hot Oil Heater 3-1	CO_2e	11,789.51	51,642.05
HOH3-2	HOH3-2	Hot Oil Heater 3-2	CO_2e	11,789.51	51,642.05
HOH3-3	HOH3-3	Hot Oil Heater 3-3	CO_2e	11,789.51	51,642.05
HTR1	HTR1	Regeneration Heater 1	CO_2e	1,925.93	8,436.04
HTR2	HTR2	Regeneration Heater 3	CO_2e	1,925.93	8,436.04
HTR3	HTR3	Regeneration Heater 3	CO_2e	1,925.93	8,436.04
ENG1	ENG1	Firewater Pump Engine	CO_2e	304.10	76.03
FLR1	FLR1	VOC Flare - Routine	CO_2e	99.05	433.85
FLR1	FLR1	VOC Flare - MSS	CO_2e	29108.79	14.55
TO1	TO1	Thermal Oxidizer 1	CO_2e	3,901.02	17,086.63
TO2	TO2	Thermal Oxidizer 2	CO_2e	3,901.02	17,086.63
TO3	TO3	Thermal Oxidizer 3	CO_2e	3,901.02	17,086.63

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	22-May-12	**Permit No.:**		**Regulated Entity No.:**	
Area Name:	Hardin County NGL Fractionation Plant			**Customer Reference No.:**	CN601229917

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

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) POUND**	**(B) TPY**
FUG1	FUG1	Train 1 Fugitives	CO_2e	27.57	120.75
FUG2	FUG2	Train 2 Fugitives	CO_2e	27.57	120.75
FUG3	FUG3	Train 3 Fugitives	CO_2e	27.57	120.75

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	22-May-12	Permit No.:	0	Regulated Entity No.:	0
Area Name:	Hardin County NGL Fractionation Plant			Customer Reference No.:	CN601229917

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

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building	6. Height Above	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	Ground (Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temp. (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
TRB1-1	TRB1-1	4700 hp Solar Centaur T4	15	3337439	345948	45.0	45.0	5.0	66.0	796			
TRB1-2	TRB1-2	4700 hp Solar Centaur T4	15	3337454	345948	45.0	45.0	5.0	66.0	796			
TRB1-3	TRB1-3	4700 hp Solar Centaur T4	15	3337423	345333	45.0	45.0	5.0	66.0	796			
TRB2-1	TRB2-1	4700 hp Solar Centaur T4	15	3337439	345333	45.0	45.0	5.0	66.0	796			
TRB2-2	TRB2-2	4700 hp Solar Centaur T4	15	3337454	345333	45.0	45.0	5.0	66.0	796			
TRB3-1	TRB3-1	4700 hp Solar Centaur T4	15	3337244	345333	45.0	45.0	5.0	66.0	796			
TRB3-2	TRB3-2	4700 hp Solar Centaur T4	15	3337259	345333	45.0	45.0	5.0	66.0	796			
HOH1-1	HOH1-1	Hot Oil Heater 1-1	15	3337398	345779	130.5	130.5	6.5	11.6	400.0			
HOH1-2	HOH1-2	Hot Oil Heater 1-2	15	3337425	345779	130.5	130.5	6.5	11.6	400.0			
HOH1-3	HOH1-3	Hot Oil Heater 1-3	15	3337453	345779	130.5	130.5	6.5	11.6	400.0			
HOH2-1	HOH2-1	Hot Oil Heater 2-1	15	3337398	345501	130.5	130.5	6.5	11.6	400.0			
HOH2-2	HOH2-2	Hot Oil Heater 2-2	15	3337425	345501	130.5	130.5	6.5	11.6	400.0			
HOH2-3	HOH2-3	Hot Oil Heater 2-3	15	3337452	345501	130.5	130.5	6.5	11.6	400.0			
HOH3-1	HOH3-1	Hot Oil Heater 3-1	15	3337245	345501	130.5	130.5	6.5	11.6	400.0			
HOH3-2	HOH3-2	Hot Oil Heater 3-2	15	3337272	345501	130.5	130.5	6.5	11.6	400.0			
HOH3-3	HOH3-3	Hot Oil Heater 3-3	15	3337300	345501	130.5	130.5	6.5	11.6	400.0			
HTR1	HTR1	Regeneration Heater 1	15	345805	3337410	76.5	76.5	3.5	9.9	540.0			
HTR2	HTR2	Regeneration Heater 3	15	345476	3337410	76.5	76.5	3.5	9.9	540.0			
HTR3	HTR3	Regeneration Heater 3	15	345476	3337287	76.5	76.5	3.5	9.9	540.0			
ENG1	ENG1	Firewater Pump Engine	15	TBD	TBD	22.0	22.0	0.7	258.4	950.0			
FLR1	FLR1	VOC Flare	15	345194	3337349	200.0	200.0	25.3	65.6	1832.0			

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	22-May-12	Permit No.:	0	Regulated Entity No.:	0
Area Name:	Hardin County NGL Fractionation Plant			Customer Reference No.:	CN601229917

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

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building	6. Height Above	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	Ground (Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temp. (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
TO1	TO1	Thermal Oxidizer 1	15	345742	3337378	100.0	100.0	5.0	20.3	750.0			
TO2	TO2	Thermal Oxidizer 2	15	345538	3337377.65	100.0	100.0	5.0	20.3	750.0			
TO3	TO3	Thermal Oxidizer 3	15	345538	3337319.51	100.0	100.0	5.0	20.3	750.0			
FUG1	FUG1	Train 1 Fugitives	15	345736	3337354	10.0	10.0			0.0			
FUG2	FUG2	Train 2 Fugitives	15	345328	3337354	10.0	10.0			0.0			
FUG3	FUG3	Train 3 Fugitives	15	345246	3337190	10.0	10.0			0.0			

EPN = Emission Point Number
FIN = Facility Identification Number

Table 4 – Combustion Units

TABLE 4

COMBUSTION UNITS

OPERATIONAL DATA	
N mber from flow diagram TO1	Model N mber(if a ailable) TBD
Name of de ice Thermal Oxidizer	Man fact rer TDB

CHARACTERISTICS OF INPUT

	Chemical Compo ition			
	Material	Min. Val e Expected lb hr	e. Val e Expected lb hr	De ign Maxim m lb hr
Wa te Material*	. Refer to attachment B			
	.			
	.			
	.			
	.			

Gro Heating Val e of Wa te Material (Wet ba i if applicable)	Bt lb	ir S pplied for Wa te Material	Minim m SCFM (°F & . p ia)	Maxim m SCFM(°F & . p ia)
	3517		TBD	TBD

Wa te Material of Contaminated Ga	Total Flow Rate lb hr		Inlet Temperat re °F	
	Minim m Expected	De ign Maxim m	Minim m Expected	De ign Maxim m
		1945.52		TBD

	Chemical Compo ition			
	Material	Min. Val e Expected lb hr	e. Val e Expected lb hr	De ign Maxim m lb hr
F el	. Natural Gas			419
	.			
	.			
	.			

Gro Heating Val e of F el	Bt lb	ir S pplied for F el	Minim m SCFM (°F & . p ia)	Maxim m SCFM(°F & . p ia)
	19,617		TBD	TBD

*De cribe how wa te material i introd ced into comb tion nit on an attached heet. S ppl drawing , dimen ioned and to cale to how clearl the de ign and operation of the nit.

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. Refer to Table 1(a)			
	2.			
	3.			
	4.			
	5.			
Temperature at Stack Exit °F	Total Flow Rate lb/hr		Velocity at Stack Exit ft/sec	
750	Minimum Expected	Maximum Expected: TBD	Minimum Expected	Maximum Expected: 20.3

COMBUSTION UNIT CHARACTERISTICS		
Chamber Volume from Drawing ft^3	Chamber Velocity at Average Chamber Temperature ft/sec	Average Chamber Temperature °F
TBD	TBD	TBD
Average Residence Time sec	Exhaust Stack Height ft	Exhaust Stack Diameter ft
TBD	100	5

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.

TABLE 4

COMBUSTION UNITS

OPERATIONAL DATA	
Number from flow diagram: TO2	Model Number(if available): TBD
Name of device: Thermal Oxidizer	Manufacturer TDB

CHARACTERISTICS OF INPUT

	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
Waste Material*	1. Refer to attachment B			
	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)
	3517		TBD	TBD

Waste Material of Contaminated Gas	Total Flow Rate lb/hr		Inlet Temperature °F	
	Minimum Expected	Design Maximum	Minimum Expected	Design Maximum
		1945.52		TBD

	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
Fuel	1. Natural Gas			419
	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)
	19,617		TBD	TBD

*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. Refer to Table 1(a)			
	2.			
	3.			
	4.			
	5.			
Temperature at Stack Exit °F	Total Flow Rate lb/hr		Velocity at Stack Exit ft/sec	
750	Minimum Expected	Maximum Expected TBD	Minimum Expected	Maximum Expected 20.3

COMBUSTION UNIT CHARACTERISTICS		
Chamber Volume from Drawing ft^3	Chamber Velocity at Average Chamber Temperature ft/sec	Average Chamber Temperature °F
TBD	TBD	TBD
Average Residence Time sec	Exhaust Stack Height ft	Exhaust Stack Diameter ft
TBD	100	5

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.

TABLE 4

COMBUSTION UNITS

OPERATIONAL DATA				
Number from flow diagram: TO3		Model Number(if available): TBD		
Name of device: Thermal Oxidizer		Manufacturer TDB		
CHARACTERISTICS OF INPUT				
Waste Material*	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
	1. Refer to attachment B			
	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)
	3517		TBD	TBD

Waste Material of Contaminated Gas	Total Flow Rate lb/hr		Inlet Temperature °F	
	Minimum Expected	Design Maximum	Minimum Expected	Design Maximum
		1945.52		TBD

Fuel	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
	1. Natural Gas			419
	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)
	19,617		TBD	TBD

*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. Refer to Table 1(a)			
	2.			
	3.			
	4.			
	5.			
Temperature at Stack Exit °F	Total Flow Rate lb/hr		Velocity at Stack Exit ft/sec	
750	Minimum Expected	Maximum Expected TBD	Minimum Expected	Maximum Expected 20.3

COMBUSTION UNIT CHARACTERISTICS		
Chamber Volume from Drawing ft^3 TBD	Chamber Velocity at Average Chamber Temperature ft/sec TBD	Average Chamber Temperature °F TBD
Average Residence Time sec TBD	Exhaust Stack Height ft 100	Exhaust Stack Diameter ft 5

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

Table 6 – Boilers and Heaters

TABLE 6

BOILERS AND HEATERS

Type of Device:	Hot Oil Heater, HOH1-1	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	100%		Average	Design Maximum 1634 (scfm)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 918.14 (Btu/scf)	Average _____ scfm* ___% excess (vol)	Design Maximum _______ scfm * ______% 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

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
6.5 (ft)	130.5 (ft)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
			11.6	400	23,127

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	Refer to Attachment B, Heater Calculations

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

TABLE 6

BOILERS AND HEATERS

Type of Device:	Hot Oil Heater, HOH1-2	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	100%		Average	Design Maximum 1634 (scfm)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 918.14 (Btu/scf)	Average _____ scfm* ___% excess (vol)	Design Maximum _______ scfm * ______% 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

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
6.5 (ft)	130.5 (ft)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp°F	scfm
			11.6	400	23,127

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	Refer to Attachment B, Heater Calculations

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

TABLE 6

BOILERS AND HEATERS

Type of Device:	Hot Oil Heater, HOH1-3	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	100%		Average	Design Maximum 1634 (scfm)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 918.14 (Btu/scf)	Average _____ scfm* ___% excess (vol)	Design Maximum _______ scfm * ______% 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

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
6.5 (ft)	130.5 (ft)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
			11.6	400	23,127

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	Refer to Attachment B, Heater Calculations

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

TABLE 6

BOILERS AND HEATERS

Type of Device:	Hot Oil Heater, HOH2-1	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	100%		Average	Design Maximum 1634 (scfm)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 918.14 (Btu/scf)	Average ____ scfm* ___% excess (vol)	Design Maximum ______ scfm * ______% 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

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
6.5 (ft)	130.5 (ft)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
			11.6	400	23,127

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	Refer to Attachment B, Heater Calculations

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

TABLE 6

BOILERS AND HEATERS

Type of Device:	Hot Oil Heater, HOH2-2	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	100%		Average	Design Maximum 1634 (scfm)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 918.14 (Btu/scf)	Average _____ scfm* ___% excess (vol)	Design Maximum _______ scfm * ______% 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

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
6.5 (ft)	130.5 (ft)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
			11.6	400	23,127

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	Refer to Attachment B, Heater Calculations

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

TABLE 6

BOILERS AND HEATERS

Type of Device:	Hot Oil Heater, HOH2-3	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	100%		Average	Design Maximum 1634 (scfm)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 918.14 (Btu/scf)	Average _____ scfm* ___% excess (vol)	Design Maximum _______ scfm * ______% 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

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
6.5 (ft)	130.5 (ft)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
			11.6	400	23,127

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	Refer to Attachment B, Heater Calculations

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

TABLE 6

BOILERS AND HEATERS

Type of Device:	Hot Oil Heater, HOH3-1	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	100%		Average	Design Maximum 1634 (scfm)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 918.14 (Btu/scf)	Average _____ scfm* ___% excess (vol)	Design Maximum ______ scfm * ______% 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

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
6.5 (ft)	130.5 (ft)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
			11.6	400	23,127

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	Refer to Attachment B, Heater Calculations

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

TABLE 6

BOILERS AND HEATERS

Type of Device:	Hot Oil Heater, HOH3-2	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	100%		Average	Design Maximum 1634 (scfm)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 918.14 (Btu/scf)	Average _____ scfm* ___% excess (vol)	Design Maximum _______ scfm * ______% 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

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
6.5 (ft)	130.5 (ft)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
			11.6	400	23,127

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	Refer to Attachment B, Heater Calculations

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

TABLE 6

BOILERS AND HEATERS

Type of Device:	Hot Oil Heater, HOH3-3	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	100%		Average	Design Maximum 1634 (scfm)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 918.14 (Btu/scf)	Average _____ scfm* ___% excess (vol)	Design Maximum ______ scfm * ______% 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

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
6.5 (ft)	130.5 (ft)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
			11.6	400	23,127

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	Refer to Attachment B, Heater Calculations

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

TABLE 6

BOILERS AND HEATERS

Type of Device:	Regeneration Heater, HTR-1	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	100%		Average	Design Maximum 266.88 (scfm)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 918.14 (Btu/scf)	Average _____ scfm* ___% excess (vol)	Design Maximum ______ scfm * ______% 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

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
3.5 (ft)	76.5 (ft)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
			9.9	540	5722

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	Refer to Attachment B, Heater Calculations

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

TABLE 6

BOILERS AND HEATERS

Type of Device:	Regeneration Heater, HTR-2	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	100%		Average	Design Maximum 266.88 (scfm)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 918.14 (Btu/scf)	Average _____ scfm* ___% excess (vol)	Design Maximum _______ scfm * ______% 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

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
3.5 (ft)	76.5 (ft)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
			9.9	540	5722

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	Refer to Attachment B, Heater Calculations

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

TABLE 6

BOILERS AND HEATERS

Type of Device:	Regeneration Heater, HTR-3	Manufacturer:	TBD
Number from flow diagram:	TBD	Model Number:	TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	100%		Average	Design Maximum 266.88 (scfm)
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 918.14 (Btu/scf)	Average _____ scfm* ___% excess (vol)	Design Maximum _______ scfm * ______% excess (vol)

HEAT TRANSFER MEDIUM

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

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 Temp °F	Exhaust scfm
3.5 (ft)	76.5 (ft)	(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)		
			9.9	540	5722

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	Refer to Attachment B, Heater Calculations

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

Table 7(a) – Vertical Fixed Roof Storage Tanks

TABLE 7(a)

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** *(Use a separate form for each tank)*.

1. Applicant's Name: DCP Midstream, LP
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. Train 1 Amine Storage Tank 4. Emission Point No. FLR1
5. FIN TBD CIN TBD
6. Status: New tank [✓] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 12 ft.
   b. Diameter: 11 ft.
   c. Maximum Liquid Height : ______ ft.
   d. Nominal Capacity or Working Volume: 5000 gallons.
   e. Turnovers per year: 1
   f. Net Throughput : 5000 gallons/year.
   g. Maximum Filling Rate: 5000 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [✓] Poor [ ]
   c. Roof Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   d. Roof Condition : Good [✓] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [ ]
   b. Roof Height: ______ ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ______ ft.
   d. Slope (*Cone Roof Only*): ______ ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve				
Pressure Vent Valve				
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ____________________ Tank No. Train 2 Amine Storage Tank

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [✓] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [✓] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: UCARSOL (50 wt% solution)
   b. CAS Number: __________________
   c. Average Liquid Surface Temperature: 85.52 °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: 0.681 psia.
   e. Liquid Molecular Weight: ___________
4. Multiple Component Information
   a. Mixture Name: ____
   b. Average Liquid Surface Temperature: _________ °F.
   c. Minimum Liquid Surface Temperature: _________ °F.
   d. Maximum Liquid Surface Temperature: _________ °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: __________ psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: _________ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: _________ psia.
   h. Liquid Molecular Weight: ____________
   i. Vapor Molecular Weight: ____________

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight
See MSDS				

TABLE 7(a)

02-95

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** *(Use a separate form for each tank)*.

1. Applicant's Name: DCP Midstream, LP
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. Train 2 Amine Storage Tank   4. Emission Point No. FLR1
5. FIN TBD   CIN TBD
6. Status: New tank [✓] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ____________

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 12 ft.
   b. Diameter: 11 ft.
   c. Maximum Liquid Height : ________ ft.
   d. Nominal Capacity or Working Volume: 5000 gallons.
   e. Turnovers per year: 1
   f. Net Throughput : 5000 gallons/year.
   g. Maximum Filling Rate: 5000 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ____________)
   b. Shell Condition : Good [✓] Poor [ ]
   c. Roof Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ____________)
   d. Roof Condition : Good [✓] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [ ]
   b. Roof Height: ________ ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ________ ft.
   d. Slope (*Cone Roof Only*): ________ ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve				
Pressure Vent Valve				
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ______________________ Tank No. Train 2 Amine Storage Tank

---

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [✓] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [✓] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: UCARSOL (50 wt% solution)
   b. CAS Number: ___________________
   c. Average Liquid Surface Temperature: 85.52 °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: 0.681 psia.
   e. Liquid Molecular Weight: ___________
4. Multiple Component Information
   a. Mixture Name: ____
   b. Average Liquid Surface Temperature: _________ °F.
   c. Minimum Liquid Surface Temperature: _________ °F.
   d. Maximum Liquid Surface Temperature: _________ °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: __________ psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: __________ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: _________ psia.
   h. Liquid Molecular Weight: ____________
   i. Vapor Molecular Weight: ____________

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight
See MSDS				

TABLE 7(a)

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: DCP Midstream, LP
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. Train 3 Amine Storage Tank 4. Emission Point No. FLR1
5. FIN TBD CIN TBD
6. Status: New tank [✓] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ____________

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 12 ft.
   b. Diameter: 11 ft.
   c. Maximum Liquid Height : __________ ft.
   d. Nominal Capacity or Working Volume: 5000 gallons.
   e. Turnovers per year: 1
   f. Net Throughput : 5000 gallons/year.
   g. Maximum Filling Rate: 5000 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______________)
   b. Shell Condition : Good [✓] Poor [ ]
   c. Roof Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______________)
   d. Roof Condition : Good [✓] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [ ]
   b. Roof Height: __________ ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ____________ ft.
   d. Slope (*Cone Roof Only*): _____________ ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve				
Pressure Vent Valve				
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ______________________ Tank No. Train 3 Amine Storage Tank

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [✓] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid
   Single [ ] *Complete Section III.3*
   Multiple [✓] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: UCARSOL (50 wt% solution)
   b. CAS Number: ___________________
   c. Average Liquid Surface Temperature: 85.52 °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: 0.681 psia.
   e. Liquid Molecular Weight: ___________
4. Multiple Component Information
   a. Mixture Name: ______________________________________
   b. Average Liquid Surface Temperature: _________ °F.
   c. Minimum Liquid Surface Temperature: _________ °F.
   d. Maximum Liquid Surface Temperature: _________ °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: __________ psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: __________ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: _________ psia.
   h. Liquid Molecular Weight: ____________
   i. Vapor Molecular Weight: ____________

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight
See MSDS				

TABLE 7(a)

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: DCP Midstream, LP
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. Train 1 Dilute Caustic Storage Tank   4. Emission Point No. ____________
5. FIN TBD   CIN TBD
6. Status: New tank [✓] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ____________

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 12 ft.
   b. Diameter: 12 ft.
   c. Maximum Liquid Height : __________ ft.
   d. Nominal Capacity or Working Volume: 8000 gallons.
   e. Turnovers per year: 1
   f. Net Throughput : 8000 gallons/year.
   g. Maximum Filling Rate: 8000 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______________)
   b. Shell Condition : Good [✓] Poor [ ]
   c. Roof Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______________)
   d. Roof Condition : Good [✓] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [ ]
   b. Roof Height: __________ ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ____________ ft.
   d. Slope (*Cone Roof Only*): _____________ ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve				
Pressure Vent Valve				
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ______________________ Tank No. Train 1 Dilute Caustic Storage Tank

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [✓] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [✓] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: Dilute Caustic
   b. CAS Number: ___________________
   c. Average Liquid Surface Temperature: 85.52 °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: 0 psia.
   e. Liquid Molecular Weight: ___________
4. Multiple Component Information
   a. Mixture Name: ________________________________
   b. Average Liquid Surface Temperature: _________ °F.
   c. Minimum Liquid Surface Temperature: _________ °F.
   d. Maximum Liquid Surface Temperature: _________ °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: __________ psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: __________ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: _________ psia.
   h. Liquid Molecular Weight: ____________
   i. Vapor Molecular Weight: ____________

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(a)

02-95

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: DCP Midstream, LP
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. Train 2 Dilute Caustic Storage Tank 4. Emission Point No. ____
5. FIN TBD CIN TBD
6. Status: New tank [✓] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ____

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 12 ft.
   b. Diameter: 12 ft.
   c. Maximum Liquid Height : ____ ft.
   d. Nominal Capacity or Working Volume: 8000 gallons.
   e. Turnovers per year: 1
   f. Net Throughput : 8000 gallons/year.
   g. Maximum Filling Rate: 8000 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ____)
   b. Shell Condition : Good [✓] Poor [ ]
   c. Roof Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ____)
   d. Roof Condition : Good [✓] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [ ]
   b. Roof Height: ____ ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ____ ft.
   d. Slope (*Cone Roof Only*): ____ ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve				
Pressure Vent Valve				
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ____________________ Tank No. Train 2 Dilute Caustic Storage Tank

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III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [✓] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid
   Single [ ] *Complete Section III.3*
   Multiple [✓] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: Dilute Caustic
   b. CAS Number: __________________
   c. Average Liquid Surface Temperature: 85.52 °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: 0 psia.
   e. Liquid Molecular Weight: ___________
4. Multiple Component Information
   a. Mixture Name: ____
   b. Average Liquid Surface Temperature: _________ °F.
   c. Minimum Liquid Surface Temperature: _________ °F.
   d. Maximum Liquid Surface Temperature: _________ °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: __________ psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: __________ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: _________ psia.
   h. Liquid Molecular Weight: ____________
   i. Vapor Molecular Weight: ____________

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(a)

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: DCP Midstream, LP
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. Train 3 Dilute Caustic Storage Tank 4. Emission Point No. ____________
5. FIN TBD CIN TBD
6. Status: New tank [✓] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ____________

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 12 ft.
   b. Diameter: 12 ft.
   c. Maximum Liquid Height : __________ ft.
   d. Nominal Capacity or Working Volume: 8000 gallons.
   e. Turnovers per year: 1
   f. Net Throughput : 8000 gallons/year.
   g. Maximum Filling Rate: 8000 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ____________)
   b. Shell Condition : Good [✓] Poor [ ]
   c. Roof Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ____________)
   d. Roof Condition : Good [✓] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [ ]
   b. Roof Height: __________ ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): __________ ft.
   d. Slope (*Cone Roof Only*): __________ ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve				
Pressure Vent Valve				
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ____________________ Tank No. Train 3 Dilute Caustic Storage Tank

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [✓] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [✓] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: Dilute Caustic
   b. CAS Number: ____________________
   c. Average Liquid Surface Temperature: 85.52 °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: 0 psia.
   e. Liquid Molecular Weight: ____________
4. Multiple Component Information
   a. Mixture Name: ____
   b. Average Liquid Surface Temperature: __________ °F.
   c. Minimum Liquid Surface Temperature: __________ °F.
   d. Maximum Liquid Surface Temperature: __________ °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: __________ psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: __________ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: __________ psia.
   h. Liquid Molecular Weight: ____________
   i. Vapor Molecular Weight: ____________

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(a)

02-95

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: DCP Midstream, LP
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. Train 1 Process Waste Water Storage Tank 4. Emission Point No. FLR1
5. FIN TBD CIN TBD
6. Status: New tank [✓] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 16 ft.
   b. Diameter: 11 ft.
   c. Maximum Liquid Height : ______ ft.
   d. Nominal Capacity or Working Volume: 11,000 gallons.
   e. Turnovers per year: 1
   f. Net Throughput : 11,000 gallons/year.
   g. Maximum Filling Rate: 200 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [✓] Poor [ ]
   c. Roof Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   d. Roof Condition : Good [✓] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [ ]
   b. Roof Height: ______ ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ______ ft.
   d. Slope (*Cone Roof Only*): ______ ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve				
Pressure Vent Valve				
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ____________________ Tank No. Train 1 Process Waste Water Storage Tank

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [✓] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid
   Single [ ] *Complete Section III.3*
   Multiple [✓] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ______________________________________
   b. CAS Number: __________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: _______ psia.
   e. Liquid Molecular Weight: ___________
4. Multiple Component Information
   a. Mixture Name: Process Waste Water
   b. Average Liquid Surface Temperature: _________ °F.
   c. Minimum Liquid Surface Temperature: _________ °F.
   d. Maximum Liquid Surface Temperature: 120 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: __________ psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: __________ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 5.335 psia.
   h. Liquid Molecular Weight: ____________
   i. Vapor Molecular Weight: 87.93

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight
n-Hexane	110-54-3		71.74	86.18
Benzene	71-43-2		7.44	78.11
n-Heptane	142-82-5		17.66	100.20
Toluene	108-88-3		2.48	92.14
Ethyl-Benzene	100-41-4		0.25	106.17
p-Xylene	106-42-3		0.44	106.17

TABLE 7(a)

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: DCP Midstream, LP
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. Train 2 Process Waste Water Storage Tank   4. Emission Point No. FLR1
5. FIN TBD   CIN TBD
6. Status: New tank [✓] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 16 ft.
   b. Diameter: 11 ft.
   c. Maximum Liquid Height : ______ ft.
   d. Nominal Capacity or Working Volume: 11,000 gallons.
   e. Turnovers per year: 1
   f. Net Throughput : 11,000 gallons/year.
   g. Maximum Filling Rate: 200 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [✓] Poor [ ]
   c. Roof Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   d. Roof Condition : Good [✓] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [ ]
   b. Roof Height: ______ ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ______ ft.
   d. Slope (*Cone Roof Only*): ______ ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve				
Pressure Vent Valve				
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ____________________ Tank No. Train 2 Process Waste Water Storage Tank

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [✓] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid
   Single [ ] *Complete Section III.3*
   Multiple [✓] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____________________
   b. CAS Number: ____________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ____________
4. Multiple Component Information
   a. Mixture Name: Process Waste Water
   b. Average Liquid Surface Temperature: _________ °F.
   c. Minimum Liquid Surface Temperature: _________ °F.
   d. Maximum Liquid Surface Temperature: 120 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: __________ psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: __________ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 5.335 psia.
   h. Liquid Molecular Weight: ____________
   i. Vapor Molecular Weight: 87.93

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight
n-Hexane	110-54-3		71.74	86.18
Benzene	71-43-2		7.44	78.11
n-Heptane	142-82-5		17.66	100.20
Toluene	108-88-3		2.48	92.14
Ethyl-Benzene	100-41-4		0.25	106.17
p-Xylene	106-42-3		0.44	106.17

TABLE 7(a)

02-95

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** *(Use a separate form for each tank*).

1. Applicant's Name: DCP Midstream, LP
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. Train 3 Process Waste Water Storage Tank 4. Emission Point No. FLR1
5. FIN TBD CIN TBD
6. Status: New tank [✓] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ____________

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 16 ft.
   b. Diameter: 11 ft.
   c. Maximum Liquid Height : ________ ft.
   d. Nominal Capacity or Working Volume: 11,000 gallons.
   e. Turnovers per year: 1
   f. Net Throughput : 11,000 gallons/year.
   g. Maximum Filling Rate: 200 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ____________)
   b. Shell Condition : Good [✓] Poor [ ]
   c. Roof Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ____________)
   d. Roof Condition : Good [✓] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [ ]
   b. Roof Height: ________ ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ________ ft.
   d. Slope (*Cone Roof Only*): ________ ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve				
Pressure Vent Valve				
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ____________________ Tank No. Train 3 Process Waste Water Storage Tank

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [✓] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [✓] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ________________________
   b. CAS Number: ____________
   c. Average Liquid Surface Temperature: ______ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: _____ psia.
   e. Liquid Molecular Weight: ______
4. Multiple Component Information
   a. Mixture Name: Process Waste Water
   b. Average Liquid Surface Temperature: ______ °F.
   c. Minimum Liquid Surface Temperature: ______ °F.
   d. Maximum Liquid Surface Temperature: 120 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: ______ psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: ______ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 5.335 psia.
   h. Liquid Molecular Weight: ______
   i. Vapor Molecular Weight: 87.93

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight
n-Hexane	110-54-3		71.74	86.18
Benzene	71-43-2		7.44	78.11
n-Heptane	142-82-5		17.66	100.20
Toluene	108-88-3		2.48	92.14
Ethyl-Benzene	100-41-4		0.25	106.17
p-Xylene	106-42-3		0.44	106.17

TABLE 7(a)

02-95

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: DCP Midstream, LP
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. Train 1 Hydrocarbon Waste Storage Tank 4. Emission Point No. FLR1
5. FIN TBD CIN TBD
6. Status: New tank [✓] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 8 ft.
   b. Diameter: 5 ft.
   c. Maximum Liquid Height : ______ ft.
   d. Nominal Capacity or Working Volume: 1000 gallons.
   e. Turnovers per year: 1
   f. Net Throughput : 1000 gallons/year.
   g. Maximum Filling Rate: 10 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [✓] Poor [ ]
   c. Roof Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   d. Roof Condition : Good [✓] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [ ]
   b. Roof Height: ______ ft. (*not including shell height*)
   c. Radius (*Dome Roof Only*): ______ ft.
   d. Slope (*Cone Roof Only*): ______ ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve				
Pressure Vent Valve				
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ____________________ Tank No. Train 1 Hydrocarbon Waste Storage Tank

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [✓] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [✓] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____________________
   b. CAS Number: ____________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ___________
4. Multiple Component Information
   a. Mixture Name: Hydrocarbon Waste
   b. Average Liquid Surface Temperature: _________ °F.
   c. Minimum Liquid Surface Temperature: _________ °F.
   d. Maximum Liquid Surface Temperature: 120 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: __________ psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: __________ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 5.335 psia.
   h. Liquid Molecular Weight: ____________
   i. Vapor Molecular Weight: 87.93

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight
n-Hexane	110-54-3		71.74	86.18
Benzene	71-43-2		7.44	78.11
n-Heptane	142-82-5		17.66	100.20
Toluene	108-88-3		2.48	92.14
Ethyl-Benzene	100-41-4		0.25	106.17
p-Xylene	106-42-3		0.44	106.17

TABLE 7(a)

02-95

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** *(Use a separate form for each tank).*
1. Applicant's Name: DCP Midstream, LP
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. Train 2 Hydrocarbon Waste Storage Tank 4. Emission Point No. FLR1
5. FIN TBD CIN TBD
6. Status: New tank [✓] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics***
1. Dimensions
   a. Shell Height : 8 ft.
   b. Diameter: 5 ft.
   c. Maximum Liquid Height : ______ ft.
   d. Nominal Capacity or Working Volume: 1000 gallons.
   e. Turnovers per year: 1
   f. Net Throughput : 1000 gallons/year.
   g. Maximum Filling Rate: 10 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [✓] Poor [ ]
   c. Roof Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   d. Roof Condition : Good [✓] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [ ]
   b. Roof Height: ______ ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ______ ft.
   d. Slope (*Cone Roof Only*): ______ ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve				
Pressure Vent Valve				
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ______________________ Tank No. Train 2 Hydrocarbon Waste Storage Tank

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [✓] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid
   Single [ ] *Complete Section III.3*
   Multiple [✓] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____
   b. CAS Number: ___________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ___________
4. Multiple Component Information
   a. Mixture Name: Hydrocarbon Waste
   b. Average Liquid Surface Temperature: _________ °F.
   c. Minimum Liquid Surface Temperature: _________ °F.
   d. Maximum Liquid Surface Temperature: 120 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: __________ psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: __________ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 5.335 psia.
   h. Liquid Molecular Weight: ____________
   i. Vapor Molecular Weight: 87.93

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight
n-Hexane	110-54-3		71.74	86.18
Benzene	71-43-2		7.44	78.11
n-Heptane	142-82-5		17.66	100.20
Toluene	108-88-3		2.48	92.14
Ethyl-Benzene	100-41-4		0.25	106.17
p-Xylene	106-42-3		0.44	106.17

TABLE 7(a)

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: DCP Midstream, LP
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. Train 3 Hydrocarbon Waste Storage Tank 4. Emission Point No. FLR1
5. FIN TBD CIN TBD
6. Status: New tank [✓] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 8 ft.
   b. Diameter: 5 ft.
   c. Maximum Liquid Height : ______ ft.
   d. Nominal Capacity or Working Volume: 1000 gallons.
   e. Turnovers per year: 1
   f. Net Throughput : 1000 gallons/year.
   g. Maximum Filling Rate: 10 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [✓] Poor [ ]
   c. Roof Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   d. Roof Condition : Good [✓] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [ ]
   b. Roof Height: ______ ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ______ ft.
   d. Slope (*Cone Roof Only*): ______ ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve				
Pressure Vent Valve				
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ______________________ Tank No. Train 3 Hydrocarbon Waste Storage Tank

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [✓] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [✓] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____
   b. CAS Number: ___________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ___________
4. Multiple Component Information
   a. Mixture Name: Hydrocarbon Waste
   b. Average Liquid Surface Temperature: _________ °F.
   c. Minimum Liquid Surface Temperature: _________ °F.
   d. Maximum Liquid Surface Temperature: 120 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: __________ psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: __________ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 5.335 psia.
   h. Liquid Molecular Weight: ____________
   i. Vapor Molecular Weight: 87.93

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight
n-Hexane	110-54-3		71.74	86.18
Benzene	71-43-2		7.44	78.11
n-Heptane	142-82-5		17.66	100.20
Toluene	108-88-3		2.48	92.14
Ethyl-Benzene	100-41-4		0.25	106.17
p-Xylene	106-42-3		0.44	106.17

Table 7(b) – Horizontal Fixed Roof Storage Tanks

TABLE 7(b)

02-95

HORIZONTAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** *(Use a separate form for each tank)*.

1. Applicant's Name: DCP Midstream, LP
2. Location (*indicate on plot plan and provide coordinates*): TBD
3. Tank No. Diesel Fuel Storage Tank
4. Emission Point No. ____
5. FIN TBD CIN TBD
6. Status: New tank [✓] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ____

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Length : 6 ft.
   b. Diameter: 3 ft.
   c. Nominal Capacity or Working Volume: 300 gallons.
   d. Turnovers per year: 1
   e. Net Throughput : 300 gallons/year.
   f. Maximum Filling Rate: 300 gallons/hour.
   g. Is the tank underground? Yes [ ] No [✓]
2. Paint Characteristics
   a. Shell Color/Shade : White/White [✓] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [ ] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ____)
   b. Shell Condition : Good [✓] Poor [ ]

3. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve				
Pressure Vent Valve				
Vacuum Vent Valve				
Open Vent Valve				

Permit No. ____________________ Tank No. Diesel Fuel Storage Tank

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [ ] Petroleum Distillates [✓] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [✓] *Complete Section III.3*

   Multiple [ ] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: Distillate Fuel Oil No. 2
   b. CAS Number: 68476-34-6
   c. Average Liquid Surface Temperature: 85.52 °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: 0.022 psia.
   e. Liquid Molecular Weight: ____________
4. Multiple Component Information
   a. Mixture Name: ____________________________
   b. Average Liquid Surface Temperature: _________ °F.
   c. Minimum Liquid Surface Temperature: _________ °F.
   d. Maximum Liquid Surface Temperature: _________ °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: __________ psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: __________ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: _________ psia.
   h. Liquid Molecular Weight: ____________
   i. Vapor Molecular Weight: ____________

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

Table 8 – Flares

TABLE 8

FLARE SYSTEMS

Number from Flow Diagram FLR1	Manufacturer & Model No. (if available) TBD

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
Refer to Attachment B, Flare Calculations		(scfm [68°F,14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1.			
	2.			
	3.			
	4.			
	5.			
	6.			
	7.			
	8.			
% of time this condition occurs				

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	0	TBD	TBD	TBD
Fuel Added to Gas Steam	0	7.5	TBD	TBD

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
	multiple	Natural Gas	5.9

For Stream Injection	Stream Pressure (psig)		Total Stream Flow	Temp. °F	Velocity (ft/sec)
	Min. Expected	Design Max.	Rate (lb/hr)		
	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) 200	Flare tip inside diameter (ft) 8
Capital Installed Cost $TBD	Annual Operating Cost $TBD

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

Table 29 – Reciprocating Engines

Texas Commission on Environmental Quality
Table 29 Reciprocating Engines

I. Engine Data

Manufacturer:	Model No.	Serial No.	Manufacture Date:
TBD	TBD	TBD	TBD
Rebuilds Date:	No. of Cylinders:	Compression Ratio:	EPN:
TBD	6	17:1	ENG1

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**:** 265 | Proposed Horsepower Rating: 265

Discharge Parameters

Stack Height (Feet)	Stack Diameter (Feet)	Stack Temperature (^{o}F)	Exit Velocity (FPS)
22	0.67	950	258.4

II. Fuel Data

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

Fuel Consumption (BTU/bhp-hr): 7000 | Heat Value: 19,676 (HHV) | 18,397 (LHV)

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

III. Emission Factors (Before Control)

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
0.0004		0.0096		0.00029		0.00004		0.000067		0.00032	

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

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: __________________________

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).

Table 31 – Combustion Turbines

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) TRB1-1

APPLICATION

_____ Electric Generation
___ Base Load ___ Peaking
_____ Gas Compression
X Other (Specify)
Propane Refrigeration Compression

CYCLE

X Simple Cycle
_____ Regenerative Cycle
_____ Cogeneration
_____ Combined Cycle

Manufacturer Solar
Model No. Centaur 4700
Serial No. TBD

Model represented is based on:
____ Preliminary Design ____ Contract Award
____ Other(specify) ____________
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 4700 (MW)(hp)
Proposed Site Operating Range 0-4700 (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 9125 Btu/hp-hr (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas _______ Process Offgas ___________ Landfill/Digester Gas
____ Fuel Oil _______ Refinery Gas ___________ Other

Backup Fuels:
X Not Provided _______ Process Offgas ___________ Ethane
____ Fuel Oil _______ Refinery Gas ___________ Other (specify) ___________

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
________ Lean Premix Combustors ________ Oxidation Catalyst ________ Water Injection X Other(specify)
X Other Low-NOx Combustor ________ SCR Catalyst ________ Steam Injection Vendor Guarantee

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) TRB1-2

APPLICATION

____ Electric Generation
___ Base Load ___ Peaking
____ Gas Compression
X Other (Specify)
Propane Refrigeration Compression

CYCLE

X Simple Cycle
____ Regenerative Cycle
____ Cogeneration
____ Combined Cycle

Manufacturer Solar
Model No. Centaur 4700
Serial No. TBD

Model represented is based on:
____ Preliminary Design ____ Contract Award
____ Other(specify) ____
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 4700 (MW)(hp)
Proposed Site Operating Range 0-4700 (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 9125 Btu/hp-hr (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ____ Process Offgas ____ Landfill/Digester Gas
____ Fuel Oil ____ Refinery Gas ____ Other

Backup Fuels:
X Not Provided ____ Process Offgas ____ Ethane
____ Fuel Oil ____ Refinery Gas ____ Other (specify) ____

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
____ Lean Premix Combustors ____ Oxidation Catalyst ____ Water Injection X Other(specify)
X Other Low-NOx Combustor ____ SCR Catalyst ____ Steam Injection Vendor Guarantee

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) TRB1-3

APPLICATION	CYCLE
___ Electric Generation ___ Base Load ___ Peaking ___ Gas Compression X Other (Specify) Propane Refrigeration Compression	X Simple Cycle ___ Regenerative Cycle ___ Cogeneration ___ Combined Cycle

Manufacturer Solar
Model No. Centaur 4700
Serial No. TBD

Model represented is based on:
___ Preliminary Design ___ Contract Award
___ Other(specify) ___
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 4700 (MW)(hp)
Proposed Site Operating Range 0-4700 (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 9125 Btu/hp-hr (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ___ Process Offgas ___ Landfill/Digester Gas
___ Fuel Oil ___ Refinery Gas ___ Other

Backup Fuels:
X Not Provided ___ Process Offgas ___ Ethane
___ Fuel Oil ___ Refinery Gas ___ Other (specify) ___

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
___ Lean Premix Combustors ___ Oxidation Catalyst ___ Water Injection X Other(specify)
X Other Low-NOx Combustor ___ SCR Catalyst ___ Steam Injection Vendor Guarantee

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) TRB2-1

APPLICATION

_____ Electric Generation
___ Base Load ___ Peaking
_____ Gas Compression
__X__ Other (Specify)
Propane Refrigeration Compression

CYCLE

_X_ Simple Cycle
____ Regenerative Cycle
____ Cogeneration
____ Combined Cycle

Manufacturer Solar
Model No. Centaur 4700
Serial No. TBD

Model represented is based on:
____ Preliminary Design ____ Contract Award
____ Other(specify) ____________
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 4700 (MW)(hp)
Proposed Site Operating Range 0-4700 (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 9125 Btu/hp-hr (Btu/k W-hr)

FUEL DATA

Primary Fuels:
_X_ Natural Gas _____ Process Offgas _____ Landfill/Digester Gas
___ Fuel Oil _____ Refinery Gas _____ Other

Backup Fuels:
_X_ Not Provided _____ Process Offgas _____ Ethane
___ Fuel Oil _____ Refinery Gas _____ Other (specify) _____

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
_____ Lean Premix Combustors _____ Oxidation Catalyst _____ Water Injection __X__ Other(specify)
__X__ Other Low-NOx Combustor _____ SCR Catalyst _____ Steam Injection Vendor Guarantee

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) TRB2-2

APPLICATION	CYCLE
___ Electric Generation ___ Base Load ___ Peaking ___ Gas Compression X Other (Specify) Propane Refrigeration Compression	X Simple Cycle ___ Regenerative Cycle ___ Cogeneration ___ Combined Cycle

Manufacturer Solar
Model No. Centaur 4700
Serial No. TBD

Model represented is based on:
___ Preliminary Design ___ Contract Award
___ Other(specify) ___
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 4700 (MW)(hp)
Proposed Site Operating Range 0-4700 (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 9125 Btu/hp-hr (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ___ Process Offgas ___ Landfill/Digester Gas
___ Fuel Oil ___ Refinery Gas ___ Other

Backup Fuels:
X Not Provided ___ Process Offgas ___ Ethane
___ Fuel Oil ___ Refinery Gas ___ Other (specify) ___

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
___ Lean Premix Combustors ___ Oxidation Catalyst ___ Water Injection X Other(specify)
X Other Low-NOx Combustor ___ SCR Catalyst ___ Steam Injection Vendor Guarantee

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) TRB3-1

APPLICATION

___ Electric Generation
___ Base Load ___ Peaking
___ Gas Compression
X Other (Specify)
Propane Refrigeration Compression

CYCLE

X Simple Cycle
___ Regenerative Cycle
___ Cogeneration
___ Combined Cycle

Manufacturer Solar
Model No. Centaur 4700
Serial No. TBD

Model represented is based on:
___ Preliminary Design ___ Contract Award
___ Other(specify) ___
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 4700 (MW)(hp)
Proposed Site Operating Range 0-4700 (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 9125 Btu/hp-hr (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ___ Process Offgas ___ Landfill/Digester Gas
___ Fuel Oil ___ Refinery Gas ___ Other

Backup Fuels:
X Not Provided ___ Process Offgas ___ Ethane
___ Fuel Oil ___ Refinery Gas ___ Other (specify) ___

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
___ Lean Premix Combustors ___ Oxidation Catalyst ___ Water Injection X Other(specify)
X Other Low-NOx Combustor ___ SCR Catalyst ___ Steam Injection Vendor Guarantee

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) TRB3-2

APPLICATION

______ Electric Generation
___ Base Load ___ Peaking
______ Gas Compression
X Other (Specify)
Propane Refrigeration Compression

CYCLE

X Simple Cycle
____ Regenerative Cycle
____ Cogeneration
____ Combined Cycle

Manufacturer Solar
Model No. Centaur 4700
Serial No. TBD

Model represented is based on:
____ Preliminary Design ____ Contract Award
____ Other(specify) ________
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 4700 (MW)(hp)
Proposed Site Operating Range 0-4700 (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO 9125 Btu/hp-hr (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ____ Process Offgas ____ Landfill/Digester Gas
____ Fuel Oil ____ Refinery Gas ____ Other

Backup Fuels:
X Not Provided ____ Process Offgas ____ Ethane
____ Fuel Oil ____ Refinery Gas ____ Other (specify) ____

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
____ Lean Premix Combustors ____ Oxidation Catalyst ____ Water Injection X Other(specify)
X Other Low-NOx Combustor ____ SCR Catalyst ____ Steam Injection Vendor Guarantee

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

ATTACHMENT B

DETAILED GHG EMISSION ESTIMATES

Start Date: | **Version: 1.0** | **Equip_Int_ID:**

Emissions Calculation: TURBINE

Facility ID: TBD
Facility: Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	TRB1-1	Model:	Solar Centaur T-4700
Name 2:	4700 hp Solar Centaur T4	Serial Number:	
Name 3:		Service Date:	
Coordinates:	UTM	Manufacture Date:	
Northing:	345,948.00	Permit Status:	
Easting:	3,337,439.03	SCC:	
Source Location Zone:	15		

Ownership:	DCP owned	Turbine HP (hp):	4,700
Status:	Not Yet Built	Fuel Heat Value (Btu/scf):	918.14
Fuel Type:	Natural Gas	Heat Rate (MMBtu/hr)	42.89
Service Type:	Refrigeration	Oil Usage (gal/month):	30
Cycle Type:	Other		
Oil Type:	Unknown	Potential fuel usage (MMscf/yr):	409.19

Stack Parameters

Stack Name:	TRB1-1	Height (ft):	45
Stack Number:	1	Diameter (ft):	5
Emission Percent:	100.00%	Temperature (^oF):	796
Stack Angle (^{o}):	0	Flow (ACFM):	77,705
Raincap:	No	Velocity (ft/s):	65.96

Emission Controls: **Control Model**

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	Emission Factor EF	Units	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	4,700	8,760	5,612.87	24,584.39	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	4,700	8,760	0.11	0.46	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	4,700	8,760	0.01	0.05	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					5,618.28	24,609.55	

Notes **Notes Date:**

Start Date: Version: 1.0 Equip_Int_ID:

Emissions Calculation: TURBINE

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	TRB1-2	Model:	Solar Centaur T-4700
Name 2:	4700 hp Solar Centaur T4	Serial Number:	
Name 3:		Service Date:	
Coordinates:	UTM	Manufacture Date:	
Northing:	345,948.00	Permit Status:	
Easting:	3,337,454.20	SCC:	
Source Location Zone:	15		

Ownership:	DCP owned	Turbine HP (hp):	4,700
Status:	Not Yet Built	Fuel Heat Value (Btu/scf):	918.14
Fuel Type:	Natural Gas	Heat Rate (MMBtu/hr)	42.89
Service Type:	Refrigeration	Oil Usage (gal/month):	30
Cycle Type:	Other		
Oil Type:	Unknown	Potential fuel usage (MMscf/yr):	409.19

Stack Parameters

Stack Name:	TRB1-2	Height (ft):	45
Stack Number:	1	Diameter (ft):	5
Emission Percent:	100.00%	Temperature (°F):	796
Stack Angle (°):	0	Flow (ACFM):	77,705
Raincap:	No	Velocity (ft/s):	65.96

Control Model

Emission Controls:

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	Emission Factor EF	Units	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	4,700	8,760	5,612.87	24,584.39	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	4,700	8,760	0.11	0.46	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	4,700	8,760	0.01	0.05	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					5,618.28	24,609.55	

Notes **Notes Date:**

Start Date: | **Version: 1.0** | **Equip_Int_ID:**

Emissions Calculation: TURBINE

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	TRB1-3	Model:	Solar Centaur T-4700
Name 2:	4700 hp Solar Centaur T4	Serial Number:	
Name 3:		Service Date:	
Coordinates:	UTM	Manufacture Date:	
Northing:	345,332.89	Permit Status:	
Easting:	3,337,423.23	SCC:	
Source Location Zone:	15		

Ownership:	DCP owned	Turbine HP (hp):	4,700
Status:	Not Yet Built	Fuel Heat Value (Btu/scf):	918.14
Fuel Type:	Natural Gas	Heat Rate (MMBtu/hr)	42.89
Service Type:	Refrigeration	Oil Usage (gal/month):	30
Cycle Type:	Other		
Oil Type:	Unknown	Potential fuel usage (MMscf/yr):	409.19

Stack Parameters

Stack Name:	TRB1-3	Height (ft):	45
Stack Number:	1	Diameter (ft):	5
Emission Percent:	100.00%	Temperature (^oF):	796
Stack Angle (^{o}):	0	Flow (ACFM):	77,705
Raincap:	No	Velocity (ft/s):	65.96

Emission Controls: **Control Model**

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	Emission Factor EF	Units	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	4,700	8,760	5,612.87	24,584.39	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	4,700	8,760	0.11	0.46	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	4,700	8,760	0.01	0.05	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					5,618.28	24,609.55	

Notes **Notes Date:**

Start Date:		Version: 1.0	Equip_Int_ID:

Emissions Calculation: TURBINE

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	TRB2-1	Model:	Solar Centaur T-4700
Name 2:	4700 hp Solar Centaur T4	Serial Number:	
Name 3:		Service Date:	
Coordinates:	UTM	Manufacture Date:	
Northing:	345,332.96	Permit Status:	
Easting:	3,337,438.81	SCC:	
Source Location Zone:	15		

Ownership:	DCP owned	Turbine HP (hp):	4,700
Status:	Not Yet Built	Fuel Heat Value (Btu/scf):	918.14
Fuel Type:	Natural Gas	Heat Rate (MMBtu/hr)	42.89
Service Type:	Refrigeration	Oil Usage (gal/month):	30
Cycle Type:	Other		
Oil Type:	Unknown	Potential fuel usage (MMscf/yr):	409.19

Stack Parameters

Stack Name:	TRB2-1	Height (ft):	45
Stack Number:	1	Diameter (ft):	5
Emission Percent:	100.00%	Temperature (^oF):	796
Stack Angle (^{o}):	0	Flow (ACFM):	77,705
Raincap:	No	Velocity (ft/s):	65.96

Emission Controls: **Control Model**

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	Emission Factor EF	Units	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	4,700	8,760	5,612.87	24,584.39	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	4,700	8,760	0.11	0.46	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	4,700	8,760	0.01	0.05	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					5,618.28	24,609.55	

Notes **Notes Date:**

Start Date: | **Version: 1.0** | **Equip_Int_ID:**

Emissions Calculation: TURBINE

Facility ID: TBD | **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	TRB2-2	Model:	Solar Centaur T-4700
Name 2:	4700 hp Solar Centaur T4	Serial Number:	
Name 3:		Service Date:	
Coordinates:	UTM	Manufacture Date:	
Northing:	345,333.02	Permit Status:	
Easting:	3,337,454.10	SCC:	
Source Location Zone:	15		

Ownership:	DCP owned	Turbine HP (hp):	4,700
Status:	Not Yet Built	Fuel Heat Value (Btu/scf):	918.14
Fuel Type:	Natural Gas	Heat Rate (MMBtu/hr)	42.89
Service Type:	Refrigeration	Oil Usage (gal/month):	30
Cycle Type:	Other		
Oil Type:	Unknown	Potential fuel usage (MMscf/yr):	409.19

Stack Parameters

Stack Name:	TRB2-2	Height (ft):	45
Stack Number:	1	Diameter (ft):	5
Emission Percent:	100.00%	Temperature (^oF):	796
Stack Angle (^{o}):	0	Flow (ACFM):	77,705
Raincap:	No	Velocity (ft/s):	65.96

Emission Controls: **Control Model**

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	Emission Factor EF	Units	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	4,700	8,760	5,612.87	24,584.39	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	4,700	8,760	0.11	0.46	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	4,700	8,760	0.01	0.05	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					5,618.28	24,609.55	

Notes **Notes Date:**

Start Date: | **Version: 1.0** | **Equip_Int_ID:**

Emissions Calculation: TURBINE

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	TRB3-1	Model:	Solar Centaur T-4700
Name 2:	4700 hp Solar Centaur T4	Serial Number:	
Name 3:		Service Date:	
Coordinates:	UTM	Manufacture Date:	
Northing:	345,332.83	Permit Status:	
Easting:	3,337,243.65	SCC:	
Source Location Zone:	15		

Ownership:	DCP owned	Turbine HP (hp):	4,700
Status:	Not Yet Built	Fuel Heat Value (Btu/scf):	918.14
Fuel Type:	Natural Gas	Heat Rate (MMBtu/hr)	42.89
Service Type:	Refrigeration	Oil Usage (gal/month):	30
Cycle Type:	Other		
Oil Type:	Unknown	Potential fuel usage (MMscf/yr):	409.19

Stack Parameters

Stack Name:	TRB3-1	Height (ft):	45
Stack Number:	1	Diameter (ft):	5
Emission Percent:	100.00%	Temperature (^oF):	796
Stack Angle (^{o}):	0	Flow (ACFM):	77,705
Raincap:	No	Velocity (ft/s):	65.96

Emission Controls: **Control Model**

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	Emission Factor EF	Units	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	4,700	8,760	5,612.87	24,584.39	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	4,700	8,760	0.11	0.46	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	4,700	8,760	0.01	0.05	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					5,618.28	24,609.55	

Notes **Notes Date:**

Start Date:		Version: 1.0	Equip_Int_ID:

Emissions Calculation: TURBINE

Facility ID: TBD

Facility: Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	TRB3-2	Model:	Solar Centaur T-4700
Name 2:	4700 hp Solar Centaur T4	Serial Number:	
Name 3:		Service Date:	
Coordinates:	UTM	Manufacture Date:	
Northing:	345,332.83	Permit Status:	
Easting:	3,337,258.91	SCC:	
Source Location Zone:	15		

Ownership:	DCP owned	Turbine HP (hp):	4,700
Status:	Not Yet Built	Fuel Heat Value (Btu/scf):	918.14
Fuel Type:	Natural Gas	Heat Rate (MMBtu/hr)	42.89
Service Type:	Refrigeration	Oil Usage (gal/month):	30
Cycle Type:	Other		
Oil Type:	Unknown	Potential fuel usage (MMscf/yr):	409.19

Stack Parameters

Stack Name:	TRB3-2	Height (ft):	45
Stack Number:	1	Diameter (ft):	5
Emission Percent:	100.00%	Temperature (^{o}F):	796
Stack Angle (^{o}):	0	Flow (ACFM):	77,705
Raincap:	No	Velocity (ft/s):	65.96

Control Model

Emission Controls:

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	Emission Factor EF	Units	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	4,700	8,760	5,612.87	24,584.39	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	4,700	8,760	0.11	0.46	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	4,700	8,760	0.01	0.05	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					5,618.28	24,609.55	

Notes **Notes Date:**

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	HOH1-1	Model:	Zeeco Other
Name 2:	HOH1-1	Serial Number:	TBD
Name 3:	Hot Oil Heater 1-1	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3337397.6	Permit Status:	TBD
Easting:	345778.64	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (MMBtu/hr):	90
Status:	Active	Fuel Heat Value (Btu/scf):	918.14
Ext. Comb.Type:	Heater	Heat Input Waste (MMBtu/hr):	N/A
Fuel Type:	Natural Gas	Waste heat Value (Btu/scf):	N/A
Equipment Usage:	Process Heater		
Configuration:	TBD		
		Potential fuel usage (MMscf/yr):	858.69

Stack Parameters

Stack Name:	HOH1-1	Height (ft):	130.5
Stack Number:	1	Diameter (ft):	6.5
Emission Percent:	100.00%	Temperature (^oF):	400
Stack Angle (^{o}):	0	Flow (ACFM):	23,127
Raincap:	No	Velocity (ft/s):	11.6

Control Model

Emission Controls:

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	nission Factor EF	Units	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	90	8,760	11,778.69	51,590.68	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	90	8,760	0.22	0.97	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	90	8,760	0.02	0.10	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					11,789.51	51,642.05	

Notes **Notes Date:**

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	HOH1-2	Model:	Zeeco Other
Name 2:	HOH1-2	Serial Number:	TBD
Name 3:	Hot Oil Heater 1-2	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3337425.1	Permit Status:	TBD
Easting:	345778.75	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (MMBtu/hr):	90
Status:	Active	Fuel Heat Value (Btu/scf):	918.14
Ext. Comb.Type:	Heater	Heat Input Waste (MMBtu/hr):	N/A
Fuel Type:	Natural Gas	Waste heat Value (Btu/scf):	N/A
Equipment Usage:	Process Heater		
Configuration:	TBD		
		Potential fuel usage (MMscf/yr):	858.69

Stack Parameters

Stack Name:	HOH1-2	Height (ft):	130.5
Stack Number:	1	Diameter (ft):	6.5
Emission Percent:	100.00%	Temperature (^oF):	400
Stack Angle (^{o}):	0	Flow (ACFM):	23,127
Raincap:	No	Velocity (ft/s):	11.6

Emission Controls: **Control Model**

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	nission Factor EF	Units	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	90	8,760	11,778.69	51,590.68	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	90	8,760	0.22	0.97	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	90	8,760	0.02	0.10	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					11,789.51	51,642.05	

Notes **Notes Date:**

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	HOH1-3	Model:	Zeeco Other
Name 2:	HOH1-3	Serial Number:	TBD
Name 3:	Hot Oil Heater 1-3	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3337452.7	Permit Status:	TBD
Easting:	345778.75	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (MMBtu/hr):	90
Status:	Active	Fuel Heat Value (Btu/scf):	918.14
Ext. Comb.Type:	Heater	Heat Input Waste (MMBtu/hr):	N/A
Fuel Type:	Natural Gas	Waste heat Value (Btu/scf):	N/A
Equipment Usage:	Process Heater		
Configuration:	TBD		
		Potential fuel usage (MMscf/yr):	858.69

Stack Parameters

Stack Name:	HOH1-3	Height (ft):	130.5
Stack Number:	1	Diameter (ft):	6.5
Emission Percent:	100.00%	Temperature (^oF):	400
Stack Angle (^{o}):	0	Flow (ACFM):	23,127
Raincap:	No	Velocity (ft/s):	11.6

Emission Controls: **Control Model**

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	nission Factor		Nominal Rating	Hrs of Operation	Estimated Emissions		Source of Emission Factor
	EF	Units	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
Carbon Dioxide	120,161	lb/MMscf	90	8,760	11,778.69	51,590.68	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	90	8,760	0.22	0.97	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	90	8,760	0.02	0.10	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					11,789.51	51,642.05	

Notes **Notes Date:**

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	HOH2-1	Model:	Zeeco Other
Name 2:	HOH2-1	Serial Number:	TBD
Name 3:	Hot Oil Heater 2-1	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3337397.9	Permit Status:	TBD
Easting:	345501.42	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (MMBtu/hr):	90
Status:	Active	Fuel Heat Value (Btu/scf):	918.14
Ext. Comb.Type:	Heater	Heat Input Waste (MMBtu/hr):	N/A
Fuel Type:	Natural Gas	Waste heat Value (Btu/scf):	N/A
Equipment Usage:	Process Heater		
Configuration:	TBD		
		Potential fuel usage (MMscf/yr):	858.69

Stack Parameters

Stack Name:	HOH2-1	Height (ft):	130.5
Stack Number:	1	Diameter (ft):	6.5
Emission Percent:	100.00%	Temperature (^oF):	400
Stack Angle (^{o}):	0	Flow (ACFM):	23,127
Raincap:	No	Velocity (ft/s):	11.6

Emission Controls: **Control Model**

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	Emission Factor EF	Units	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	90	8,760	11,778.69	51,590.68	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	90	8,760	0.22	0.97	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	90	8,760	0.02	0.10	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					11,789.51	51,642.05	

Notes **Notes Date:**

Start Date:	Version: 1.0	Equip_Int_ID:

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	HOH2-2	Model:	Zeeco Other
Name 2:	HOH2-2	Serial Number:	TBD
Name 3:	Hot Oil Heater 2-2	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3337425.1	Permit Status:	TBD
Easting:	345501.42	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (MMBtu/hr):	90
Status:	Active	Fuel Heat Value (Btu/scf):	918.14
Ext. Comb.Type:	Heater	Heat Input Waste (MMBtu/hr):	N/A
Fuel Type:	Natural Gas	Waste heat Value (Btu/scf):	N/A
Equipment Usage:	Process Heater		
Configuration:	TBD		
		Potential fuel usage (MMscf/yr):	858.69

Stack Parameters

Stack Name:	HOH2-2	Height (ft):	130.5
Stack Number:	1	Diameter (ft):	6.5
Emission Percent:	100.00%	Temperature (^oF):	400
Stack Angle (^{o}):	0	Flow (ACFM):	23,127
Raincap:	No	Velocity (ft/s):	11.6

Emission Controls: **Control Model**

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	nission Factor		Nominal Rating	Hrs of Operation	Estimated Emissions		Source of Emission Factor
	EF	Units	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
Carbon Dioxide	120,161	lb/MMscf	90	8,760	11,778.69	51,590.68	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	90	8,760	0.22	0.97	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	90	8,760	0.02	0.10	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					11,789.51	51,642.05	

Notes **Notes Date:**

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	HOH2-3	Model:	Zeeco Other
Name 2:	HOH2-3	Serial Number:	TBD
Name 3:	Hot Oil Heater 2-3	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3337452.3	Permit Status:	TBD
Easting:	345501.4	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (MMBtu/hr):	90
Status:	Active	Fuel Heat Value (Btu/scf):	918.14
Ext. Comb.Type:	Heater	Heat Input Waste (MMBtu/hr):	N/A
Fuel Type:	Natural Gas	Waste heat Value (Btu/scf):	N/A
Equipment Usage:	Process Heater		
Configuration:	TBD		
		Potential fuel usage (MMscf/yr):	858.69

Stack Parameters

Stack Name:	HOH2-3	Height (ft):	130.5
Stack Number:	1	Diameter (ft):	6.5
Emission Percent:	100.00%	Temperature (^oF):	400
Stack Angle (^{o}):	0	Flow (ACFM):	23,127
Raincap:	No	Velocity (ft/s):	11.6

Emission Controls: **Control Model**

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	nission Factor EF	Units	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	90	8,760	11,778.69	51,590.68	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	90	8,760	0.22	0.97	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	90	8,760	0.02	0.10	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					11,789.51	51,642.05	

Notes **Notes Date:**

Start Date:	Version: 1.0	Equip_Int_ID:

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	HOH3-1	Model:	Zeeco Other
Name 2:	HOH3-1	Serial Number:	TBD
Name 3:	Hot Oil Heater 3-1	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3337245.3	Permit Status:	TBD
Easting:	345501.42	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (MMBtu/hr):	90
Status:	Active	Fuel Heat Value (Btu/scf):	918.14
Ext. Comb.Type:	Heater	Heat Input Waste (MMBtu/hr):	N/A
Fuel Type:	Natural Gas	Waste heat Value (Btu/scf):	N/A
Equipment Usage:	Process Heater		
Configuration:	TBD		
		Potential fuel usage (MMscf/yr):	858.69

Stack Parameters

Stack Name:	HOH3-1	Height (ft):	130.5
Stack Number:	1	Diameter (ft):	6.5
Emission Percent:	100.00%	Temperature (^oF):	400
Stack Angle (^{o}):	0	Flow (ACFM):	23,127
Raincap:	No	Velocity (ft/s):	11.6

Emission Controls: **Control Model**

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	nission Factor		Nominal Rating	Hrs of Operation	Estimated Emissions		Source of Emission Factor
	EF	Units	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
Carbon Dioxide	120,161	lb/MMscf	90	8,760	11,778.69	51,590.68	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	90	8,760	0.22	0.97	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	90	8,760	0.02	0.10	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					11,789.51	51,642.05	

Notes **Notes Date:**

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	HOH3-2	Model:	Zeeco Other
Name 2:	HOH3-2	Serial Number:	TBD
Name 3:	Hot Oil Heater 3-2	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3337272.5	Permit Status:	TBD
Easting:	345501.42	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (MMBtu/hr):	90
Status:	Active	Fuel Heat Value (Btu/scf):	918.14
Ext. Comb.Type:	Heater	Heat Input Waste (MMBtu/hr):	N/A
Fuel Type:	Natural Gas	Waste heat Value (Btu/scf):	N/A
Equipment Usage:	Process Heater		
Configuration:	TBD		
		Potential fuel usage (MMscf/yr):	858.69

Stack Parameters

Stack Name:	HOH3-2	Height (ft):	130.5
Stack Number:	1	Diameter (ft):	6.5
Emission Percent:	100.00%	Temperature (^oF):	400
Stack Angle (^{o}):	0	Flow (ACFM):	23,127
Raincap:	No	Velocity (ft/s):	11.6

Emission Controls: **Control Model**

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	nission Factor EF	Units	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	90	8,760	11,778.69	51,590.68	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	90	8,760	0.22	0.97	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	90	8,760	0.02	0.10	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					11,789.51	51,642.05	

Notes **Notes Date:**

Start Date:	Version: 1.0	Equip_Int_ID:

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	HOH3-3	Model:	Zeeco Other
Name 2:	HOH3-3	Serial Number:	TBD
Name 3:	Hot Oil Heater 3-3	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3337299.9	Permit Status:	TBD
Easting:	345501.42	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (MMBtu/hr):	90
Status:	Active	Fuel Heat Value (Btu/scf):	918.14
Ext. Comb.Type:	Heater	Heat Input Waste (MMBtu/hr):	N/A
Fuel Type:	Natural Gas	Waste heat Value (Btu/scf):	N/A
Equipment Usage:	Process Heater		
Configuration:	TBD		
		Potential fuel usage (MMscf/yr):	858.69

Stack Parameters

Stack Name:	HOH3-3	Height (ft):	130.5
Stack Number:	1	Diameter (ft):	6.5
Emission Percent:	100.00%	Temperature (^{o}F):	400
Stack Angle (^{o}):	0	Flow (ACFM):	23,127
Raincap:	No	Velocity (ft/s):	11.6

Emission Controls: **Control Model**

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	nission Factor EF	Units	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	90	8,760	11,778.69	51,590.68	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	90	8,760	0.22	0.97	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	90	8,760	0.02	0.10	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					11,789.51	51,642.05	

Notes **Notes Date:**

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	HTR1	Model:	Zeeco Other
Name 2:	HTR1	Serial Number:	TBD
Name 3:	Regeneration Heater 1	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3337410	Permit Status:	TBD
Easting:	345804.72	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (mmbtu/hr):	14.7
Status:	Active	Fuel Heat Value (btu/scf):	918.14
Ext. Comb.Type:	Heater	Heat Input Wste (mmbtu/hr):	N/A
Fuel Type:	Natural Gas	Waste heat Value (btu/scf):	N/A
Equipment Usage:	Process Heater		
Configuration:			
		Potential fuel usage (MMscf/yr):	140.25

Stack Parameters

Stack Name:	HTR1	Height (ft):	76.5
Stack Number:	10	Diameter (ft):	3.5
Emission Percent:	100.00%	Temperature (^oF):	540
Stack Angle (^{o}):	0	Flow (ACFM):	5,722
Raincap:	No	Velocity (ft/s):	9.9

Control Model

Emission Controls:

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	Emission Factor EF	Units	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	14.7	8760	1,923.85	8,426.48	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	14.7	8760	0.04	0.16	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	14.7	8760	0.004	0.02	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					1,925.93	8,436.04	

Notes **Notes Date:**

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	HTR2	Model:	Zeeco Other
Name 2:	HTR2	Serial Number:	TBD
Name 3:	Regeneration Heater 3	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3337409.6	Permit Status:	TBD
Easting:	345475.77	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (mmbtu/hr):	14.7
Status:	Active	Fuel Heat Value (btu/scf):	918.14
Ext. Comb.Type:	Heater	Heat Input Wste (mmbtu/hr):	N/A
Fuel Type:	Natural Gas	Waste heat Value (btu/scf):	N/A
Equipment Usage:	Process Heater		
Configuration:			
		Potential fuel usage (MMscf/yr):	140.25

Stack Parameters

Stack Name:	HTR2	Height (ft):	76.5
Stack Number:	10	Diameter (ft):	3.5
Emission Percent:	100.00%	Temperature (^oF):	540
Stack Angle (^{o}):	0	Flow (ACFM):	5,722
Raincap:	No	Velocity (ft/s):	9.9

Control Model

Emission Controls:

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	Emission Factor EF	Units	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	14.7	8760	1,923.85	8,426.48	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	14.7	8760	0.04	0.16	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	14.7	8760	0.004	0.02	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					1,925.93	8,436.04	

Notes **Notes Date:**

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: HEATER/BOILER/REBOILER

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	HTR3	Model:	Zeeco Other
Name 2:	HTR3	Serial Number:	TBD
Name 3:	Regeneration Heater 3	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3337287.4	Permit Status:	TBD
Easting:	345475.77	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (mmbtu/hr):	14.7
Status:	Active	Fuel Heat Value (btu/scf):	918.14
Ext. Comb.Type:	Heater	Heat Input Wste (mmbtu/hr):	N/A
Fuel Type:	Natural Gas	Waste heat Value (btu/scf):	N/A
Equipment Usage:	Process Heater		
Configuration:			
		Potential fuel usage (MMscf/yr):	140.25

Stack Parameters

Stack Name:	HTR3	Height (ft):	76.5
Stack Number:	10	Diameter (ft):	3.5
Emission Percent:	100.00%	Temperature (^oF):	540
Stack Angle (^{o}):	0	Flow (ACFM):	5,722
Raincap:	No	Velocity (ft/s):	9.9

Control Model

Emission Controls:

Potential operation: 8,760 hr/yr

Potential Emissions

Pollutant	Emission Factor EF	Units	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	(tpy)	Source of Emission Factor
Carbon Dioxide	120,161	lb/MMscf	14.7	8760	1,923.85	8,426.48	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	14.7	8760	0.04	0.16	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	14.7	8760	0.004	0.02	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					1,925.93	8,436.04	

Notes **Notes Date:**

Emissions Calculation: FIREWATER PUMP ENGINE

Facility ID:

Facility: Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	ENG1	Model:		
Name 2:	ENG1	Serial Number:	TBD	
Name 3:	Firewater Pump Engine	Service Date:	TBD	
Coordinates:	UTM	Manufacture Date:	TBD	
Northing:	TBD	Permit Status:	TBD	
Easting:	TBD	SCC:	TBD	
Source Location Zone:	15			

Ownership:	DCP owned	Horsepower (bhp):	265	
Status:	Active	Heat Rate (MMBtu/hr):	1.86	
Service Type:	Residue	Rotations per Minute (rpm):	2350	
Configuration:	Diesel	Fuel Consumption (btu/hp-hr):	7000	AP-42, Table 3-3.1 (Footnote A)
Fuel Type:	Residue	Fuel Heat Value (MMBtu/gallon):	0.138	40 CFR 98 Subpart C, Table C-1
Oil Type:	Unknown	Oil Usage (gal/month):	30	
Compression Ratio:		Cylinders:	16	
Ignition Timing:		Potential fuel usage (gallons/yr):	6739.13	
Operating Range (%):				

Stack Parameters

Stack Name:	ENG1	Height (ft):	22
Stack Number:	1	Diameter (ft):	0.67
Emission Percent:	100.00%	Temperature (^oF):	950
Stack Angle (^{o}):	0	Flow (ACFM):	5466
Raincap:	No	Velocity (ft/s):	258.4

Emission Controls: **Control Model**

Potential operation: 500 hr/yr

Potential Emissions

Pollutant	Emission Factor EF	Emission Factor Units	Nominal Rating (hp)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
Carbon Dioxide	163.05	lb/MMBTU	265	500	303.27	75.82	40 CFR 98 Subpart C, Table C-1
Methane	0.007	lb/MMBTU	265	500	0.01	0.003	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.001	lb/MMBTU	265	500	0.002	0.001	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					304.10	76.03	

Notes **Notes Date:**

Start Date:		Version: 1.0	Equip_Int_ID:

Emissions Calculation: FLARE

Facility ID: TBD

Facility: Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	FLR1
Equipment ID:	FLR1
Source Description:	Air-assisted Flare
Equipment Usage:	VOC Flare
Equipment Make:	
Equipment Model:	
Serial Number:	N/A
Date in Service:	
Equipment Configuration:	Smokeless, air-assisted
Number of Pilots:	Multiple
Continuous Fuel Flow to Pilots:	None - Automatic Ignition

SCC:	31000205
Coordinates:	UTM
Northing:	3E+06
Easting:	345194
Source Location Zc	15
Potential Operation	8760 hr/yr
Stack ID:	FLARE-1
Stack Height:	200 ft. agl
Effective Stack Diameter:	25.272 in
Exit Velocity:	65.61 ft/sec
Exit Temperature:	1832 °F
Volume Flow Rate:	13713 ft^3/min

Potential Emissions

Pollutant	Supplemental gas Estimated Emissions (lb/hr)	(tpy)	Waste Gas Estimated Emissions (lb/hr)	(tpy)	MSS Estimated Emissions (lb/hr)	(tpy)	Total Estimated Emissions (lb/hr)	(tpy)
CO_2	96.75	423.79	2.20	9.64	29021.17	14.51	29120.12	447.93
N_2O	2.00E-04	8.11E-04	8.44E-07	3.70E-06	0.02	0.00001	0.02	0.00
CH_4	0.64	2.80	0.00	0.00	3.15	0.002	3.79	2.80
CO_2e	96.85	424.21	2.20	9.64	29093.52	14.55	29192.57	448.40

Emissions Calculation: FLARE

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	FLR1	Model:	
Name 2:	FLR1	Serial Number:	TBD
Name 3:	VOC Flare	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:		Permit Status:	TBD
Easting:		SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (MMBtu/hr):	0.74
Status:	Active	Fuel Heat Value (Btu/scf):	918.14
Ext. Comb.Type:			
Fuel Type:	Natural Gas		
Equipment Usage:			
Configuration:			
		Potential fuel usage (MMscf/yr):	7.05

Stack Parameters

Stack Name:	FLR1	Height (ft):	200
Stack Number:		Effective Diameter (ft):	2.106
Emission Percent:		Temperature (oF):	1832
Stack Angle (o):		Flow (ACFM):	13714
Raincap:		Velocity (ft/s):	65.6

Control Model

Emission Controls:

Potential operation: 8760 hr/yr

Potential Emissions: Products of Combustion: fuel

Pollutant	Emission Factor		Nominal Rating	Hrs of Operation	Estimated Emissions		Source of Emission Factor
	EF	Units	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
Carbon Dioxide	120161	lb/MMscf	0.74	8,760	96.75	423.79	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	0.74	8,760	0.002	0.01	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	0.74	8,760	0.0002	0.001	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					96.85	424.21	

Notes **Notes Date:**

Hardin County NGL Fractionation Plant

Speciated Vent Gas Streams Sent to Flare

Control Efficiency 98.0%

Compound	Amine Storage Tanks (lb/hr)	Process Waste Water Tanks (lb/hr)	Hydrocarbon Waste Tanks (lb/hr)	Uncontrolled Vent Gas (lb/hr)	Molecular Weight (lb/lb-mol)	Moles of Hydrocarbon (lb-mol/hr)	Number of Carbon Moles (mol-C/hr)	Moles of CO_2 from Combustion (lb-mol/hr)	Heat of Combustion (Btu/lb)	Heat Input (MMBtu/hr)	Controlled Flare Emissions (lb/hr)	Controlled Flare Emissions (tpy)
Water	13.15	-	-	13.15	-	-	-	-	-	-	13.15	57.58
methane	-	-	-	-	16.04	0.00	1	0.00	21537.00	0.00E+00	0.00E+00	0.00E+00
n-hexane*	-	2.40E-01	2.40E-01	4.81E-01	86.10	5.59E-03	6	3.35E-02	19,403.00	9.33E-03	9.62E-03	4.21E-02
Cyclohexane	-	0.00E+00	0.00E+00	-	-	-	-	-	-	0.00E+00	-	-
2-Methylpentane	-	0.00E+00	0.00E+00	-	-	-	-	-	-	0.00E+00	-	-
C7	-	5.92E-02	5.92E-02	1.18E-01	100.12	1.18E-03	7	8.26E-03	19,246.00	2.27E-03	2.36E-03	1.03E-02
Benzene*	-	2.49E-02	2.49E-02	5.00E-02	78.11	6.40E-04	6	3.84E-03	18,341.00	9.17E-04	1.00E-03	4.38E-03
Toluene*	-	8.38E-04	8.38E-04	2.00E-03	92.14	2.17E-05	7	1.52E-04	18,716.00	3.74E-05	4.00E-05	1.75E-04
Ethylbenzene*	-	8.38E-04	8.38E-04	2.00E-03	106.17	1.88E-05	8	1.50E-04	17,600.13	3.52E-05	4.00E-05	1.75E-04
xylenes*	-	1.47E-03	1.47E-03	3.00E-03	106.16	2.83E-05	8	2.26E-04	17,760.00	5.33E-05	6.00E-05	2.63E-04
MDEA	0.01	-	-	0.01	119.16	1.09E-04	5	5.45E-04	-	-	2.60E-04	1.14E-03
Piperazine	0.08	-	-	0.08	86.14	9.17E-04	4	3.67E-03	-	-	1.58E-03	6.92E-03
Total	**13.24**	**0.33**	**0.33**	**13.90**		**0.009**		**0.05**		**0.013**	**13.16**	**57.65**
Total Hydrocarbons	**0.09**	**0.33**	**0.33**	**0.75**							**0.02**	**0.07**
Total HAPs	**-**	**0.33**	**0.33**	**0.66**							**0.01**	**0.05**
Total VOC	**0.09**	**0.33**	**0.33**	**0.75**							**0.02**	**0.07**

*HAP

Vent Gas HHV[3] (MMBtu/scf): 0.001235

Potential operation: 8,760

Potential Emissions: Products of Combustion Acid Gas

Pollutant	Emission Factor EF	Units	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
Carbon Dioxide	0.05	lb-mol/hr		8760	2.20	9.64	40 CFR 98 Subpart W [1]
Methane	0	lb/hr		8760	0	0	40 CFR 98 Subpart W [2]
Nitrous Oxide	0.0002	lb/MMBtu		8760	8.E-07	4.E-06	40 CFR 98 Subpart W [3]
Carbon Dioxide Equivalent					2.20	9.64	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate emissions.

[2] Assumes 98% destruction of methane. Remaining 2% of methane in waste gas is emitted as methane.

[3] Uses the vent gas heating value of 1.235 x 10^{-3} MMBtu/scf and 1 x 10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

Hardin County NGL Fractionation Plant

Speciated Waste Gas Streams Sent to Flare

	Change Feed Coalescer Elements	**Change Lean Amine Filters**	**Change Lean Amine Carbon**	**Repair Ethane Product Pump Seals**	**Repair Propane Reflux Pump Seals**	**Change Gasoline Product Filters**
	Emissions (lb/hr)	**Emissions (lb/hr)**	**Emissions (lb/hr)**	**Emissions (lb/hr)**	**Emissions (lb/hr)**	**Emissions (lb/hr)**
Compound						
carbon dioxide (uncontroll	26.54	0.41	3.28	-	-	-
hydrogen sulfide	0.01	-	-	-	-	-
methyl mercaptan	0.67	-	-	0.00	0.00	-
ethyl mercaptan	1.09	-	-	0.00	0.00	-
nPMercaptan	0.43	-	-	0.00	0.00	-
nBMercaptan	0.04	-	-	0.00	0.00	-
nitrogen (uncontrolled)	-	0.17	1.35	-	-	-
Water	1.27	-	-	-	-	-
methane	25.34	13.53	108.24	6.11	0.00	0.00
ethane	3,310.97	0.78	6.25	591.08	4.03	0.00
propane	2,036.62	0.09	0.75	4.27	95.41	0.00
i-butane	617.08	0.02	0.12	0.00	0.54	0.02
n-butane	1,097.86	-	-	0.00	0.02	3.12
i-pentane	488.99	-	-	0.00	0.00	53.05
n-pentane	395.13	-	-	0.00	0.00	50.23
n-hexane*	415.80	-	-	0.00	0.00	45.85
C7	191.77	-	-	0.00	0.00	27.49
Benzene*	29.86	-	-	0.00	0.00	7.06
Toluene*	29.45	-	-	0.00	0.00	6.97
Ethylbenzene*	7.36	-	-	0.00	0.00	1.74
Total	**8676.28**	**15.00**	**120.00**	**601.47**	**100.01**	**195.53**
Total Hydrocarbons	**8646.23**	**14.42**	**115.37**	**601.47**	**100.01**	**195.53**
Total HAPs	**674.25**	**0.00**	**0.00**	**0.00**	**0.00**	**89.11**
Total VOC	**5309.92**	**0.11**	**0.87**	**4.28**	**95.97**	**195.53**

*HAP

Vent Gas HHV[3] (MMBtu/scf): 0.001235

Potential operation:

Potential Emissions: Products of Combustion MSS Gas

Pollutant	Emission Factor	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
Carbon Dioxide		1	29,021.17	14.51	40 CFR 98 Subpart W [1]
Methane		1	3.15	0.002	40 CFR 98 Subpart W [2]
Nitrous Oxide		1	0.02	0.00001	40 CFR 98 Subpart W [3]
Carbon Dioxide Equivalent			29,093.52	14.55	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate emissions.

[2] Assumes 98% destruction of methane. Remaining 2% of methane in waste gas is emitted as methane.

[3] Uses the vent gas heating value of 1.235×10^{-3} MMBtu/scf and 1×10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

Hardin County NGL Fractionation Plant

Speciated Waste Gas Streams Sent to Flare

	Repair Propane Compressor Seals	Repair Propane Compressor Turbine	Repair Propane Compressor Turbine	Uncontrolled MSS	Molecular Weight
	Emissions (lb/hr)	Emissions (lb/hr)	Emissions (lb/hr)	Emissions	
Compound				(lb/hr)	(lb/lb-mol)
carbon dioxide (uncontrolled)	-	-	0.14	30.37	-
hydrogen sulfide	-	-	-	0.01	-
methyl mercaptan	0.00	0.00	-	0.67	48.11
ethyl mercaptan	0.00	0.00	-	1.09	62.13
nPMercaptan	0.00	0.00	-	0.43	76.16
nBMercaptan	0.00	0.00	-	0.04	90.19
nitrogen (uncontrolled)	-	-	0.06	1.58	-
Water	-	-	-	1.27	-
methane	0.00	0.00	4.51	157.73	16.04
ethane	1.21	0.40	0.26	3,914.99	30.07
propane	28.62	9.54	0.03	2,175.34	44.10
i-butane	0.16	0.05	0.01	618.01	58.12
n-butane	0.01	0.00	-	1,101.01	58.12
i-pentane	0.00	0.00	-	542.04	72.15
n-pentane	0.00	0.00	-	445.36	72.15
n-hexane*	0.00	0.00	-	461.65	86.10
C7	0.00	0.00	-	219.27	100.12
Benzene*	0.00	0.00	-	36.93	78.11
Toluene*	0.00	0.00	-	36.42	92.14
Ethylbenzene*	0.00	0.00	-	9.10	106.17
Total	**30.00**	**10.00**	**5.00**	**9753.290**	
Total Hydrocarbons	**30.00**	**10.00**	**4.81**	**9717.830**	
Total HAPs	**0.00**	**0.00**	**0.00**	**763.360**	
Total VOC	**28.79**	**9.60**	**0.04**	**5645.120**	

8760

Hardin County NGL Fractionation Plant

Speciated Waste Gas Streams Sent to Flare

	Moles of Hydrocarbon	Number of Carbon Moles	Moles of CO_2 from Combustion	Heat of Combustion	Heat Input	Controlled Flare	
						Emissions	
Compound	**(lb-mol/hr)**	**(mol-C/hr)**	**(lb-mol/hr)**	**(Btu/lb)**	**(MMBtu/hr)**	**(lb/hr)**	**(tpy)**
carbon dioxide (uncontrolled)	-	-	-	0.00	0.00	30.37	0.02
hydrogen sulfide	-	-	-	6545.00	0.00	0.00	0.00
methyl mercaptan	0.01	1	0.01	11054.00	0.01	0.01	0.00
ethyl mercaptan	0.02	2	0.04	15000.00	0.02	0.02	0.00
nPMercaptan	0.01	3	0.02	15000.00	0.01	0.01	0.00
nBMercaptan	0.00	4	0.00	15000.00	0.00	0.00	0.00
nitrogen (uncontrolled)	-	-	-	-	0.00	1.58	0.00
Water	-	-	-	-	0.00	1.27	0.00
methane	9.83	1	9.83	21537.00	3.40	3.15	0.002
ethane	130.20	2	260.39	20394.00	79.84	78.30	0.04
propane	49.33	3	147.98	19807.00	43.09	43.51	0.02
i-butane	10.63	4	42.53	19529.00	12.07	12.36	0.01
n-butane	18.94	4	75.78	19815.00	21.82	22.02	0.01
i-pentane	7.51	5	37.56	19478.00	10.56	10.84	0.01
n-pentane	6.17	5	30.86	20485.00	9.12	8.91	0.00
n-hexane*	5.36	6	32.17	19403.00	8.96	9.23	0.00
C7	2.19	7	15.33	19246.00	4.22	4.39	0.00
Benzene*	0.47	6	2.84	18341.00	0.68	0.74	0.00
Toluene*	0.40	7	2.77	18716.00	0.68	0.73	0.00
Ethylbenzene*	0.09	8	0.69	17600.13	0.16	0.18	0.00
Total	**241.16**		**658.73**		**194.62**	**230.050**	**0.120**
Total Hydrocarbons						**194.357**	**0.097**
Total HAPs						**10.882**	**0.005**
Total VOC						**112.902**	**0.056**

Hardin County NGL Fractionation Plant

Thermal Oxidizer Emission Summary Sheet

Source ID Number	TO1		
Equipment ID	TO1		
Source Description	Thermal Oxidizer 1		
Equipment Usage			
Equipment Make		Proposed Operation	8760 hr/yr
Equipment Model			
Serial Number			
Date in Service			

Potential Emissions Summary (fuel combustion + waste gas combustion)

Pollutant	**Fuel Gas Emissions**		**Waste Gas Emissions**		**Total Estimated Emissions**	
	(lb/hr)	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**
Carbon Dioxide	1,079.71	4,729.15	2,818.70	12,345.89	3,898.41	17,075.03
Methane	0.02	0.09	0.06	0.27	0.08	0.36

Emissions Calculation: THERMAL OXIDIZER

Facility ID: TBD **Facility:** Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	TO1	Model:	
Name 2:	TO1	Serial Number:	TBD
Name 3:	Thermal Oxidizer 1	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3337377.8	Permit Status:	TBD
Easting:	345742.33	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (mmbtu/hr):	8.25
Status:	Active	Fuel Heat Value (btu/scf):	918.14
Ext. Comb.Type:	Heater		
Fuel Type:	Residue		
Equipment Usage:			
Configuration:			
		Potential fuel usage (MMscf/yr):	78.71

Stack Parameters

Stack Name:	TO1	Height (ft):	100
Stack Number:		Diameter (ft):	5
Emission Percent:		Temperature (oF):	750
Stack Angle (o):		Flow (ACFM):	23914
Raincap:		Velocity (ft/s):	20.3

Emission Controls: **Control Model**

Potential operation: 8760 hr/yr

Potential Emissions: Products of Combustion: fuel

Pollutant	Emission Factor		Nominal Rating	Hrs of Operation	Estimated Emissions		Source of Emission Factor
	EF	Units	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
Carbon Dioxide	120161	lb/MMscf	8.25	8760	1,079.71	4,729.15	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	8.25	8760	0.02	0.09	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	8.25	8760	0.002	0.009	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					1,080.75	4,733.83	

Notes **Notes Date:**

Hardin County NGL Fractionation Plant
Speciated Thermal Oxidizer Emissions from Amine Unit Vent Gas
EPN: TO1

Control Efficiency 99.9%

Compound	Amine Regenerator Reflux Drum Emissions (lb/hr)	Off-Gas from Caustic/Gasoline Treating Emissions (lb/hr)	Total Uncontrolled Waste Gas Emissions (lb/hr)	Molecular Weight (lb/lb-mol)	Moles of Hydrocarbon (lb-mol/hr)	Number of Carbon Atoms per Molecule	Moles of CO_2 from Combustion (lb-mol/hr)	Heat of Combustion (Btu/lb)	Heat Input (Btu/hr)	Controlled TO Emissions (lb/hr)	Controlled TO Emissions (tpy)
carbon dioxide (uncontroll	1706.42	1.76	1708.18	-	-	-	-	0.00	0.00	1,708.18	7,481.83
hydrogen sulfide	0.68	0.00	0.68	34.08	0.02	-	-	6545.00	4450.60	0.00	0.00
Methyl mercaptan	0.96	1.92	2.89	48.11	0.06	1	0.06	11054.00	31946.06	0.00	0.01
Ethyl mercaptan	0.62	0.00	0.62	62.13	0.01	2	0.02	15000.00	9300.00	0.00	0.00
sulfur dioxide (from H2S c	-	-	-	-	-	-	-	-	-	5.77	25.26
nitrogen (uncontrolled)	-	197.75	197.75	-	-	-	-	-	-	197.75	197.75
Water	66.32	8.65	74.97	-	-	-	-	-	-	74.97	328.37
methane	0.77	60.79	61.56	16.04	3.84	1	3.84	21537.00	1325817.72	0.06	0.27
ethane	65.12	2.10	67.22	30.07	2.24	2	4.47	20394.00	1370884.68	0.07	0.29
propane	9.61	0.44	10.05	44.10	0.23	3	0.68	19807.00	199060.35	0.01	0.04
i-butane	0.60	31.38	31.98	58.12	0.55	4	2.20	19529.00	624537.42	0.03	0.14
n-butane	1.57	62.77	64.34	58.12	1.11	4	4.43	19815.00	1274897.10	0.06	0.28
i-pentane	0.17	64.21	64.39	72.15	0.89	5	4.46	19478.00	1254188.42	0.06	0.28
n-pentane	0.15	44.73	44.89	72.15	0.62	5	3.11	20485.00	919571.65	0.04	0.20
Cyclopentane	0.00	0.00	-	-	-	-	-	-	-	-	-
n-hexane*	0.03	4.31	4.34	86.10	0.05	6	0.30	19403.00	84209.02	0.00	0.02
Cyclohexane	0.00	0.00	-	-	-	-	-	-	-	-	-
2-Methylpentane	0.00	0.00	-	-	-	-	-	-	-	-	-
C7	0.00	16.03	16.04	100.12	0.16	7	1.12	19426.00	311593.04	0.02	0.07
Methylcyclohexane	0.00	0.00	-	-	-	-	-	-	-	-	-
2,2,4-Trimethylpentane	0.00	0.00	-	-	-	-	-	-	-	-	-
Benzene*	3.65	0.78	4.44	78.11	0.06	6	0.34	18341.00	81434.04	0.00	0.02
Toluene*	1.48	0.92	2.40	92.14	0.03	7	0.18	18716.00	44918.40	0.00	0.01
Ethylbenzene*	0.15	0.00	0.15	106.17	0.00	8	0.01	17600.13	2640.02	0.00015	0.00
xylenes*	0.00	0.00	0.00	106.16	0.00	8	0.00	17760.00	0.00	0.00	0.00
Octanes	0.00	0.00	-	-	-	-	-	-	-	-	-
Nonanes	0.00	0.00	-	-	-	-	-	-	-	-	-
Decanes	0.00	0.00	-	-	-	-	-	-	-	-	-
C11+	0.00	0.00	-	-	-	-	-	-	-	-	-
MDEA	0.00	0.00	0.0E+00	119.16	0.00	5	0.00	-	-	0.00	0.00
Piperazine	0.00	0.00	0.0E+00	86.14	0.00	4	0.00	-	-	0.00	0.00
Total	**1858.31**	**498.56**	**2356.89**		**9.86**		**25.23**		**7539448.52**	**1,987.04**	**8,034.85**
Total Hydrocarbons	**83.30**	**288.48**	**371.80**							**0.37**	**1.63**
Total HAPs	**5.32**	**22.04**	**27.37**							**0.01**	**0.05**
Total VOC	**17.42**	**225.58**	**243.02**							**0.24**	**1.06**

*HAP

Vent Gas HHV[3] (MMBtu/scf): 0.001235

Potential operation: 8760

Potential Emissions: Products of Combustion Acid Gas

Pollutant	Emission Factor EF	Units	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
Carbon Dioxide		lb-mol/hr		8760	2818.70	12345.89	40 CFR 98 Subpart W [1]
Methane	0.062	lb/hr		8760	0.062	0.270	40 CFR 98 Subpart W [2]
Nitrous Oxide	0.0002	lb/MMBtu		8760	9.E-04	4.E-03	40 CFR 98 Subpart W [3]
Carbon Dioxide Equivalent					2820.27	12352.80	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate emissions.

[2] Assumes 98% destruction of methane. Remaining 2% of methane in waste gas is emitted as methane.

[3] Uses the vent gas heating value of 1.235 x 10^{-3} MMBtu/scf and 1 x 10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

Hardin County NGL Fractionation Plant

Thermal Oxidizer Emission Summary Sheet

Source ID Number	TO2		
Equipment ID	TO2		
Source Description	Thermal Oxidizer 2		
Equipment Usage			
Equipment Make		Proposed Operation	8760 hr/yr
Equipment Model			
Serial Number			
Date in Service			

Potential Emissions Summary (fuel combustion + waste gas combustion)

Pollutant	Fuel Gas Emissions		Waste Gas Emissions		Total Estimated Emissions	
	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Carbon Dioxide	1,079.71	4,729.15	2,818.70	12,345.89	3,898.41	17,075.03
Methane	0.02	0.09	0.06	0.27	0.08	0.36

Emissions Calculation: THERMAL OXIDIZER

Facility ID: TBD

Facility: Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	TO2	Model:	
Name 2:	TO2	Serial Number:	TBD
Name 3:	Thermal Oxidizer 2	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3337377.65	Permit Status:	TBD
Easting:	345537.86	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (mmbtu/hr):	8.25
Status:	Active	Fuel Heat Value (btu/scf):	918.14
Ext. Comb.Type:	Heater		
Fuel Type:	Residue		
Equipment Usage:			
Configuration:			
		Potential fuel usage (MMscf/yr):	78.71

Stack Parameters

Stack Name:	TO2	Height (ft):	100
Stack Number:		Diameter (ft):	5
Emission Percent:		Temperature (oF):	750
Stack Angle (o):		Flow (ACFM):	23914
Raincap:		Velocity (ft/s):	20.3

Emission Controls: **Control Model**

Potential operation: 8760 hr/yr

Potential Emissions: Products of Combustion: fuel

Pollutant	Emission Factor		Nominal Rating	Hrs of Operation	Estimated Emissions		Source of Emission Factor
	EF	Units	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
Carbon Dioxide	120161	lb/MMscf	8.25	8760	1,079.71	4,729.15	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	8.25	8760	0.02	0.09	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	8.25	8760	0.002	0.009	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					1,080.75	4,733.83	

Notes **Notes Date:**

Hardin County NGL Fractionation Plant
Speciated Thermal Oxidizer Emissions from Amine Unit Vent Gas
EPN: TO2

Control Efficiency 99.9%

Compound	Amine Regenerator Reflux Drum Emissions (lb/hr)	Off-Gas from Caustic/Gasoline Treating Emissions (lb/hr)	Total Uncontrolled Waste Gas Emissions (lb/hr)	Molecular Weight (lb/lb-mol)	Moles of Hydrocarbon (lb-mol/hr)	Number of Carbon Atoms per Molecule	Moles of CO_2 from Combustion (lb-mol/hr)	Heat of Combustion (Btu/lb)	Heat Input (Btu/hr)	Controlled TO Emissions (lb/hr)	Controlled TO Emissions (tpy)
carbon dioxide (uncontroll	1706.42	1.76	1708.18	-	-	-	-	0.00	0.00	1,708.18	7,481.83
hydrogen sulfide	0.68	0.00	0.68	34.08	0.02	-	-	6545.00	4450.60	0.00	0.00
Methyl mercaptan	0.96	1.92	2.89	48.11	0.06	1	0.06	11054.00	31946.06	0.00	0.01
Ethyl mercaptan	0.62	0.00	0.62	62.13	0.01	2	0.02	15000.00	9300.00	0.00	0.00
sulfur dioxide (from H2S c	-	-	-	-	-	-	-	-	-	5.77	25.26
nitrogen (uncontrolled)	-	197.75	197.75	-	-	-	-	-	-	197.75	197.75
Water	66.32	8.65	74.97	-	-	-	-	-	-	74.97	328.37
methane	0.77	60.79	61.56	16.04	3.84	1	3.84	21537.00	1325817.72	0.06	0.27
ethane	65.12	2.10	67.22	30.07	2.24	2	4.47	20394.00	1370884.68	0.07	0.29
propane	9.61	0.44	10.05	44.10	0.23	3	0.68	19807.00	199060.35	0.01	0.04
i-butane	0.60	31.38	31.98	58.12	0.55	4	2.20	19529.00	624537.42	0.03	0.14
n-butane	1.57	62.77	64.34	58.12	1.11	4	4.43	19815.00	1274897.10	0.06	0.28
i-pentane	0.17	64.21	64.39	72.15	0.89	5	4.46	19478.00	1254188.42	0.06	0.28
n-pentane	0.15	44.73	44.89	72.15	0.62	5	3.11	20485.00	919571.65	0.04	0.20
Cyclopentane	0.00	0.00	-	-	-	-	-	-	-	-	-
n-hexane*	0.03	4.31	4.34	86.10	0.05	6	0.30	19403.00	84209.02	0.00	0.02
Cyclohexane	0.00	0.00	-	-	-	-	-	-	-	-	-
2-Methylpentane	0.00	0.00	-	-	-	-	-	-	-	-	-
C7	0.00	16.03	16.04	100.12	0.16	7	1.12	19426.00	311593.04	0.02	0.07
Methylcyclohexane	0.00	0.00	-	-	-	-	-	-	-	-	-
2,2,4-Trimethylpentane	0.00	0.00	-	-	-	-	-	-	-	-	-
Benzene*	3.65	0.78	4.44	78.11	0.06	6	0.34	18341.00	81434.04	0.00	0.02
Toluene*	1.48	0.92	2.40	92.14	0.03	7	0.18	18716.00	44918.40	0.00	0.01
Ethylbenzene*	0.15	0.00	0.15	106.17	0.00	8	0.01	17600.13	2640.02	0.00015	0.00
xylenes*	0.00	0.00	0.00	106.16	0.00	8	0.00	17760.00	0.00	0.00	0.00
Octanes	0.00	0.00	-	-	-	-	-	-	-	-	-
Nonanes	0.00	0.00	-	-	-	-	-	-	-	-	-
Decanes	0.00	0.00	-	-	-	-	-	-	-	-	-
C11+	0.00	0.00	-	-	-	-	-	-	-	-	-
MDEA	0.00	0.00	0.0E+00	119.16	0.00	5	0.00	-	-	0.00	0.00
Piperazine	0.00	0.00	0.0E+00	86.14	0.00	4	0.00	-	-	0.00	0.00
Total	**1858.31**	**498.56**	**2356.89**		**9.86**		**25.23**		**7539448.52**	**1,987.04**	**8,034.85**
Total Hydrocarbons	**83.30**	**288.48**	**371.80**							**0.37**	**1.63**
Total HAPs	**5.32**	**22.04**	**27.37**							**0.01**	**0.05**
Total VOC	**17.42**	**225.58**	**243.02**							**0.24**	**1.06**

*HAP

Vent Gas HHV[3] (MMBtu/scf): 0.001235

Potential operation: 8760

Potential Emissions: Products of Combustion Acid Gas

Pollutant	Emission Factor EF	Units	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
Carbon Dioxide		lb-mol/hr		8760	2818.70	12345.89	40 CFR 98 Subpart W [1]
Methane	0.062	lb/hr		8760	0.062	0.270	40 CFR 98 Subpart W [2]
Nitrous Oxide	0.0002	lb/MMBtu		8760	9.E-04	4.E-03	40 CFR 98 Subpart W [3]
Carbon Dioxide Equivalent					2820.27	12352.80	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate emissions.

[2] Assumes 98% destruction of methane. Remaining 2% of methane in waste gas is emitted as methane.

[3] Uses the vent gas heating value of 1.235×10^{-3} MMBtu/scf and 1×10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

Hardin County NGL Fractionation Plant

Thermal Oxidizer Emission Summary Sheet

Source ID Number	TO3		
Equipment ID	TO3		
Source Description	Thermal Oxidizer 3		
Equipment Usage			
Equipment Make		Proposed Operation	8760 hr/yr
Equipment Model			
Serial Number			
Date in Service			

Potential Emissions Summary (fuel combustion + waste gas combustion)

Pollutant	**Fuel Gas Emissions**		**Waste Gas Emissions**		**Total Estimated Emissions**	
	(lb/hr)	**(tpy)**	**(lb/hr)**	**(tpy)**	**(lb/hr)**	**(tpy)**
Carbon Dioxide	1,079.71	4,729.15	2,818.70	12,345.89	3,898.41	17,075.03
Methane	0.02	0.09	0.06	0.27	0.08	0.36

Emissions Calculation: THERMAL OXIDIZER

Facility ID: TBD

Facility: Hardin County NGL Fractionation Plant

Equipment Information

Source ID Number:	TO3	Model:	
Name 2:	TO3	Serial Number:	TBD
Name 3:	Thermal Oxidizer 3	Service Date:	TBD
Coordinates:	UTM	Manufacture Date:	TBD
Northing:	3337319.51	Permit Status:	TBD
Easting:	345537.86	SCC:	TBD
Source Location Zone:	15		

Ownership:	DCP owned	Heat Input Fuel (mmbtu/hr):	8.25
Status:	Active	Fuel Heat Value (btu/scf):	918.14
Ext. Comb.Type:	Heater		
Fuel Type:	Residue		
Equipment Usage:			
Configuration:			
		Potential fuel usage (MMscf/yr):	78.71

Stack Parameters

Stack Name:	TO3	Height (ft):	100
Stack Number:		Diameter (ft):	5
Emission Percent:		Temperature (oF):	750
Stack Angle (o):		Flow (ACFM):	23914
Raincap:		Velocity (ft/s):	20.3

Control Model

Emission Controls:

Potential operation: 8760 hr/yr

Potential Emissions: Products of Combustion: fuel

Pollutant	Emission Factor		Nominal Rating	Hrs of Operation	Estimated Emissions		Source of Emission Factor
	EF	Units	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
Carbon Dioxide	120161	lb/MMscf	8.25	8760	1,079.71	4,729.15	40 CFR 98 Subpart C, Table C-1
Methane	2.27	lb/MMscf	8.25	8760	0.02	0.09	40 CFR 98 Subpart C, Table C-2
Nitrous Oxide	0.23	lb/MMscf	8.25	8760	0.002	0.009	40 CFR 98 Subpart C, Table C-2
Carbon Dioxide Equivalent					1,080.75	4,733.83	

Notes **Notes Date:**

Hardin County NGL Fractionation Plant
Speciated Thermal Oxidizer Emissions from Amine Unit Vent Gas
EPN: TO3

Control Efficiency 99.9%

Compound	Amine Regenerator Reflux Drum Emissions (lb/hr)	Off-Gas from Caustic/Gasoline Treating Emissions (lb/hr)	Total Uncontrolled Waste Gas Emissions (lb/hr)	Molecular Weight (lb/lb-mol)	Moles of Hydrocarbon (lb-mol/hr)	Number of Carbon Atoms per Molecule	Moles of CO_2 from Combustion (lb-mol/hr)	Heat of Combustion (Btu/lb)	Heat Input (Btu/hr)	Controlled TO Emissions (lb/hr)	Controlled TO Emissions (tpy)
carbon dioxide (uncontroll	1706.42	1.76	1708.18	-	-	-	-	0.00	0.00	1,708.18	7,481.83
hydrogen sulfide	0.68	0.00	0.68	34.08	0.02	-	-	6545.00	4450.60	0.00	0.00
Methyl mercaptan	0.96	1.92	2.89	48.11	0.06	1	0.06	11054.00	31946.06	0.00	0.01
Ethyl mercaptan	0.62	0.00	0.62	62.13	0.01	2	0.02	15000.00	9300.00	0.00	0.00
sulfur dioxide (from H2S c	-	-	-	-	-	-	-	-	-	5.77	25.26
nitrogen (uncontrolled)	-	197.75	197.75	-	-	-	-	-	-	197.75	197.75
Water	66.32	8.65	74.97	-	-	-	-	-	-	74.97	328.37
methane	0.77	60.79	61.56	16.04	3.84	1	3.84	21537.00	1325817.72	0.06	0.27
ethane	65.12	2.10	67.22	30.07	2.24	2	4.47	20394.00	1370884.68	0.07	0.29
propane	9.61	0.44	10.05	44.10	0.23	3	0.68	19807.00	199060.35	0.01	0.04
i-butane	0.60	31.38	31.98	58.12	0.55	4	2.20	19529.00	624537.42	0.03	0.14
n-butane	1.57	62.77	64.34	58.12	1.11	4	4.43	19815.00	1274897.10	0.06	0.28
i-pentane	0.17	64.21	64.39	72.15	0.89	5	4.46	19478.00	1254188.42	0.06	0.28
n-pentane	0.15	44.73	44.89	72.15	0.62	5	3.11	20485.00	919571.65	0.04	0.20
Cyclopentane	0.00	0.00	-	-	-	-	-	-	-	-	-
n-hexane*	0.03	4.31	4.34	86.10	0.05	6	0.30	19403.00	84209.02	0.00	0.02
Cyclohexane	0.00	0.00	-	-	-	-	-	-	-	-	-
2-Methylpentane	0.00	0.00	-	-	-	-	-	-	-	-	-
C7	0.00	16.03	16.04	100.12	0.16	7	1.12	19426.00	311593.04	0.02	0.07
Methylcyclohexane	0.00	0.00	-	-	-	-	-	-	-	-	-
2,2,4-Trimethylpentane	0.00	0.00	-	-	-	-	-	-	-	-	-
Benzene*	3.65	0.78	4.44	78.11	0.06	6	0.34	18341.00	81434.04	0.00	0.02
Toluene*	1.48	0.92	2.40	92.14	0.03	7	0.18	18716.00	44918.40	0.00	0.01
Ethylbenzene*	0.15	0.00	0.15	106.17	0.00	8	0.01	17600.13	2640.02	0.00015	0.00
xylenes*	0.00	0.00	0.00	106.16	0.00	8	0.00	17760.00	0.00	0.00	0.00
Octanes	0.00	0.00	-	-	-	-	-	-	-	-	-
Nonanes	0.00	0.00	-	-	-	-	-	-	-	-	-
Decanes	0.00	0.00	-	-	-	-	-	-	-	-	-
C11+	0.00	0.00	-	-	-	-	-	-	-	-	-
MDEA	0.00	0.00	0.0E+00	119.16	0.00	5	0.00	-	-	0.00	0.00
Piperazine	0.00	0.00	0.0E+00	86.14	0.00	4	0.00	-	-	0.00	0.00
Total	**1858.31**	**498.56**	**2356.89**		**9.86**		**25.23**		**7539448.52**	**1,987.04**	**8,034.85**
Total Hydrocarbons	**83.30**	**288.48**	**371.80**							**0.37**	**1.63**
Total HAPs	**5.32**	**22.04**	**27.37**							**0.01**	**0.05**
Total VOC	**17.42**	**225.58**	**243.02**							**0.24**	**1.06**

*HAP

Vent Gas HHV[3] (MMBtu/scf): 0.001235

Potential operation: 8760

Potential Emissions: Products of Combustion Acid Gas

Pollutant	Emission Factor EF	Units	Nominal Rating (MMBtu/hr)	Hrs of Operation (hrs/yr)	Estimated Emissions (lb/hr)	Estimated Emissions (tpy)	Source of Emission Factor
Carbon Dioxide		lb-mol/hr		8760	2818.70	12345.89	40 CFR 98 Subpart W [1]
Methane	0.062	lb/hr		8760	0.062	0.270	40 CFR 98 Subpart W [2]
Nitrous Oxide	0.0002	lb/MMBtu		8760	9.E-04	4.E-03	40 CFR 98 Subpart W [3]
Carbon Dioxide Equivalent					2820.27	12352.80	

[1] Assumes 100% conversion of all carbons in hydrocarbon compounds in waste stream to CO_2. Emission factor is multiplied by molecular weight of CO_2 (44.01 lb/lb-mol) to estimate emissions.

[2] Assumes 98% destruction of methane. Remaining 2% of methane in waste gas is emitted as methane.

[3] Uses the vent gas heating value of 1.235×10^{-3} MMBtu/scf and 1×10^{-4} kg N_2O/MMBtu as specified in Equation W-40.

Hardin County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs :FUG1, FUG2, FUG3
Total Emissions
The emission estimates below are for 1 train. Each train will be identical.

Component	Amine		Acid Gas	Ethane		Fuel Gas	Plant Feed		Hourly	Annual
	gas (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	gas (lb/hr)	gas (lb/hr)	light liquid (lb/hr)	Emissions (lb/hr)	Emissions (tpy)
CO2	-	-	0.237	-	-	0.039	0.000	0.005	**0.28**	**1.23**
Methane	0.005	-	0.000	0.002	0.014	1.274	0.000	0.004	**1.30**	**5.69**
Total GHG	**0.01**	**0.00**	**0.24**	**0.00**	**0.01**	**1.31**	**0.00**	**0.01**	**1.58**	**6.92**
Total CO_2e	**0.11**	**0.00**	**0.24**	**0.04**	**0.30**	**26.79**	**0.00**	**0.10**	**27.57**	**120.75**

*HAPs

Hardin County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1, FUG2, FUG3
Amine Fugitives

Operating Schedule (hr/yr) 8760
Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	76	0.00992	75%	0.188
	Light Liquid	1584	0.0055	75%	2.178
Flanges	Gas	20	0.00086	30%	0.012
	Light Liquid	844	0.000243	30%	0.144
Pump	Gas	0	0.00529	75%	0.000
	Light Liquid	28	0.02866	75%	0.201
Compressor Seals	Gas	0	0.0194	75%	0.000
	Light Liquid	0	0.0165	75%	0.000
Relief Valves	Gas	4	0.0194	75%	0.019
	Light Liquid	24	0.0165	0%	0.396
Total Emissions	**Gas**				**0.22**
	Light Liquid				**2.92**

[1]Detailed review of process flow diagrams.

[2]TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000

[3]TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000, based off 28M with annual connector monitoring.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Methane	2.31%	5.08E-03	2.23E-02	-	-	-
Total GHG	**2.31%**	**0.005**	**0.02**	**0**	**0**	**0**
Total CO_2e		**0.107**	**0.47**		**0**	**0**

Hardin County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1, FUG2, FUG3
Acid Gas Fugitives

Operating Schedule (hr/yr) 8760
Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	88	0.00992	75%	0.218
	Light Liquid	0	0.0055	75%	0.000
Flanges	Gas	28	0.00086	30%	0.017
	Light Liquid	0	0.000243	30%	0.000
Pump	Gas	0	0.00529	75%	0.000
	Light Liquid	0	0.02866	75%	0.000
Compressor Seals	Gas	0	0.0194	75%	0.000
	Light Liquid	0	0.0165	75%	0.000
Relief Valves	Gas	4	0.0194	75%	0.019
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**0.25**
	Light Liquid				**0.00**

[1]Detailed review of process flow diagrams.
[2]TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000
[3]TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000, based off 28M with annual connector monitoring.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
CO2	93.00%	2.37E-01	6.02E-02	-	-	-
Methane	0.04%	1.02E-04	2.59E-05	-	-	-
Total GHG	**93.04%**	**2.37E-01**	**6.03E-02**	**0**	**0**	**0**
Total CO_2e		**2.39E-01**	**6.08E-02**		**0**	**0**

Hardin County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1, FUG2, FUG3
Ethane Fugitives

Operating Schedule (hr/yr) 8760
Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	60	0.00992	75%	0.149
	Light Liquid	652	0.0055	75%	0.897
Flanges	Gas	28	0.00086	30%	0.017
	Light Liquid	332	0.000243	30%	0.056
Pump	Gas	0	0.00529	75%	0.000
	Light Liquid	24	0.02866	75%	0.172
Compressor Seals	Gas	0	0.0194	75%	0.000
	Light Liquid	0	0.0165	75%	0.000
Relief Valves	Gas	4	0.0194	75%	0.019
	Light Liquid	16	0.0165	0%	0.264
Total Emissions	**Gas**				**0.19**
	Light Liquid				**1.39**

[1]Detailed review of process flow diagrams.
[2]TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000
[3]TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000, based off 28M with annual connector monitoring.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
Methane	1.02%	0.002	0.008	1.02%	0.014	0.062
Total GHG	**1%**	**0.002**	**0.008**	**1%**	**0.014**	**0.062**
Total CO_2e		**0.040**	**0.174**		**0.298**	**1.303**

Hardin County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1, FUG2, FUG3
Fuel Gas Fugitives

Operating Schedule (hr/yr) 8760
Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	508	0.00992	75%	1.260
	Light Liquid	0	0.0055	75%	0.000
Flanges	Gas	124	0.00086	30%	0.075
	Light Liquid	0	0.000243	30%	0.000
Pump	Gas	0	0.00529	75%	0.000
	Light Liquid	0	0.02866	75%	0.000
Compressor Seals	Gas	0	0.0194	75%	0.000
	Light Liquid	0	0.0165	75%	0.000
Relief Valves	Gas	16	0.0194	75%	0.078
	Light Liquid	0	0.0165	0%	0.000
Total Emissions	**Gas**				**1.41**
	Light Liquid				**0.00**

[1]Detailed review of process flow diagrams.
[2]TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000
[3]TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000, based off 28M with annual connector monitoring.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
CO2	2.73%	0.039	0.169	-	-	-
Methane	90.20%	1.274	5.579	-	-	-
Total GHG	**92.93%**	**1.312**	**5.748**	**0**	**0**	**0**
Total CO_2e		**26.786**	**117.324**		**0**	**0**

Hardin County NGL Fractionation Plant

Fugitive Emissions Calculations
EPNs: FUG1, FUG2, FUG3
Plant Feed Fugitives

Operating Schedule (hr/yr) 8760
Fugitive Emission Calculations

Emission Sources	Phase	Source Count[1]	Uncontrolled Emission Factor[2] (lb/hr/source)	Control Factor[3]	Hourly Emission (lb/hr)
Valves	Gas	0	0.00992	75%	0.000
	Light Liquid	564	0.0055	75%	0.776
Flanges	Gas	12	0.00086	30%	0.007
	Light Liquid	428	0.000243	30%	0.073
Pump	Gas	0	0.00529	75%	0.000
	Light Liquid	0	0.02866	75%	0.000
Compressor Seals	Gas	0	0.0194	75%	0.000
	Light Liquid	0	0.0165	75%	0.000
Relief Valves	Gas	0	0.0194	75%	0.000
	Light Liquid	28	0.0165	0%	0.462
Total Emissions	**Gas**				**0.01**
	Light Liquid				**1.31**

[1]Detailed review of process flow diagrams.
[2]TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000
[3]TCEQ guidance document on "Equipment Leak Fugitives" dated October 2000, based off 28M with annual connector monitoring.

Component	Gas Stream			Light Liquid Stream		
	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Weight Percent (%)	Hourly Emissions (lb/hr)	Annual Emissio (tpy)
CO2	0.35%	2.53E-05	1.11E-04	0.35%	4.59E-03	2.01E-02
Methane	0.34%	2.46E-05	1.08E-04	0.34%	4.46E-03	1.95E-02
Total GHG	**0.007**	**0.000**	**0.00**	**0.0069**	**0.009**	**0.040**
Total CO_2e		**0.001**	**0.00**		**0.098**	**0.430**

Tank ID			TBD
Tank Name			**Amine Storage Tank**
Tank Capacity (bbl)			**119.0**
Tank Capacity (gallons)			**5,000**
Tank Type			**Vertical Fixed Roof**
Product Name			**Amine (50-wt%)**
Crude Oil (Y/N)			N
Capacity		bbl	119.0
Vapor Molecular Weight	M_V	lb/lb-mol	54.41
Liquid Density	W_L	lb/gal	8.72
Maximum Filling Rate	Q	bbl/hr	119.0
Diameter	D	ft	11
Tank Shell Height	H_S	ft	12
Paint Solar Absorptance	α		0.17
Daily Total Solar Insolation Factor[1]	I	Btu/ft²·d	1828
Daily Maximum Ambient Temperature	T_{AX}	ºF	93.6
Daily Minimum Ambient Temperature	T_{AN}	ºF	72.5
Daily Average Ambient Temperature	T_{AA}	ºR	542.72
Daily Average Liquid Surface Temp.	T_{LA}	ºR	545.19
Daily Maximum Liquid Surface Temp.	T_{LX}	ºR	554.67
Daily Minimum Liquid Surface Temp.	T_{LN}	ºR	539.21
Daily Vapor Temperature Range	DT_V	ºR	23.89
Vapor Pressure @ T_{LX}	P_{VX}	psia	0.681
Turnover Factor	K_N		1.0
Working Loss Product Factor	K_P		1.0
Maximum Hourly Emission Rate	L_W	**lb/hr**	**4.41**

Daily Average Liquid Surface Temp.	T_{LA}	ºF	85.52
Daily Maximum Liquid Surface Temp.	T_{LX}	ºF	95.00
Daily Minimum Liquid Surface Temp.	T_{LN}	ºF	79.54
		ºF	psia
		40	0.1520
		50	0.1994
		60	0.2614
		70	0.3428
		80	0.4496
		90	0.5895
		100	0.7731
			Amine (50-wt%)

Speciated Maximum Hourly Emissions		
Component	**Weight % in Vapor Phase**	**Speciated Emissions (lb/hr)**
Nitrogen	0.00%	0.00
CO_2	0.00%	0.00
Methane	0.00%	0.00
Ethane	0.00%	0.00
Propane	0.00%	0.00
i-Butane	0.00%	0.00
n-Butane	0.00%	0.00
i-Pentane	0.00%	0.00
n-Pentane	0.00%	0.00
n-Hexane	0.00%	0.00
Benzene	0.00%	0.00
n-Heptane	0.00%	0.00
Toluene	0.00%	0.00
E-Benzene	0.00%	0.00
p-Xylene	0.00%	0.00
H_2O	99.30%	4.38
COS	0.00%	0.00
H2S	0.00%	0.00
M-Mercaptan	0.00%	0.00
E-Mercaptan	0.00%	0.00
nPMercaptan	0.00%	0.00
nBMercaptan	0.00%	0.00
ThermialB_1	0.00%	0.00
Oxygen	0.00%	0.00
Argon	0.00%	0.00
CO	0.00%	0.00
MDEA	0.10%	0.00
Piperazine	0.60%	0.03
Total VOC Emissions (lb/hr):		**0.03**
Total HAP Emissions (lb/hr):		**0.00**

[1] The daily solar insolation factor and daily ambient temperature are for Houston, TX in the month of July (July factors are used to calculate maximum hourly emissions).

[2] The daily maximum liquid surface temperature is the greater of the value calucalted using AP-42, Chapter 7.1 or 95°F

Tank ID			**TBD**
Tank Name			**Process Waste Water Tank**
Tank Capacity (bbl)			**261.9**
Tank Capacity (gallons)			**11,000**
Tank Type			**Vertical Fixed Roof**
Product Name			**Waste Water**
Crude Oil (Y/N)			N
Capacity		bbl	261.9
Vapor Molecular Weight	M_V	lb/lb-mol	87.93
Liquid Density	W_L	lb/gal	8.35
Maximum Filling Rate	Q	bbl/hr	4.8
Diameter	D	ft	11
Tank Shell Height	H_S	ft	16
Paint Solar Absorptance	α		0.17
Daily Total Solar Insolation Factor[1]	I	$Btu/ft^2 \cdot d$	1828
Daily Maximum Ambient Temperature[1]	T_{AX}	ºF	120
Daily Minimum Ambient Temperature[1]	T_{AN}	ºF	120.0
Daily Average Ambient Temperature	T_{AA}	ºR	579.67
Daily Average Liquid Surface Temp.	T_{LA}	ºR	579.67
Daily Maximum Liquid Surface Temp.	T_{LX}	ºR	579.67
Daily Minimum Liquid Surface Temp.	T_{LN}	ºR	579.67
Daily Vapor Temperature Range	DT_V	ºR	8.70
Vapor Pressure @ T_{LX}[2]	P_{VX}	psia	5.335
Turnover Factor	K_N		1.0
Working Loss Product Factor	K_P		1.0
Percent of Vapors that are VOC[3]		%	5.0%
Maximum Hourly Emission Rate	**L_W**	**lb/hr**	**0.11**

Speciated Maximum Hourly Emissions		
Component[2]	**Weight % in Vapor Phase**	**Speciated Emissions (lb/hr)**
Nitrogen	0.00%	0.000
CO_2	0.00%	0.000
Methane	0.00%	0.000
Ethane	0.00%	0.000
Propane	0.00%	0.000
i-Butane	0.00%	0.000
n-Butane	0.00%	0.000
i-Pentane	0.00%	0.000
n-Pentane	0.00%	0.000
n-Hexane	71.74%	0.080
Benzene	7.44%	0.008
n-Heptane	17.66%	0.020
Toluene	2.48%	0.003
E-Benzene	0.25%	0.000
p-Xylene	0.44%	0.000
H_2O	0.00%	0.000
COS	0.00%	0.000
H2S	0.00%	0.000
M-Mercaptan	0.00%	0.000
E-Mercaptan	0.00%	0.000
nPMercaptan	0.00%	0.000
nBMercaptan	0.00%	0.000
ThermialB_1	0.00%	0.000
Oxygen	0.00%	0.000
Argon	0.00%	0.000
CO	0.00%	0.000
MDEA	0.00%	0.000
Piperazine	0.00%	0.000
Total VOC Emissions (lb/hr):		**0.112**
Total HAP Emissions (lb/hr):		**0.092**

[1] The daily solar insolation factor and daily ambient temperature are for Houston, TX in the month of July (July factors are used to calculate maximum hourly emissions).

[2] The vapor pressure and component speciation profile was obtained from the vapor mass fraction calculated using TANKS 4.09d at a temperature of 120°F.

[3] This tank stores wastewater that contains approximately 1% of natural gas liquid heavy products. It is conservatively assumed that 5% of the vapors vented from the storage of pure product are representative of the working and flash emissions from this tank.

Tank ID			TBD
Tank Name			Hydrocarbon Waste Storage Tank
Tank Capacity (bbl)			23.8
Tank Capacity (gallons)			1,000
Tank Type			Vertical Fixed Roof
Product Name			Y-Grade Feed
Crude Oil (Y/N)			N
Capacity		bbl	23.8
Vapor Molecular Weight	M_V	lb/lb-mol	87.93
Liquid Density	W_L	lb/gal	8.35
Maximum Filling Rate	Q	bbl/hr	0.24
Diameter	D	ft	5
Tank Shell Height	H_S	ft	8
Paint Solar Absorptance	α		0.17
Daily Total Solar Insolation Factor[1]	I	Btu/ft^2·d	1828
Daily Maximum Ambient Temperature[1]	T_{AX}	ºF	120.0
Daily Minimum Ambient Temperature[1]	T_{AN}	ºF	120.0
Daily Average Ambient Temperature	T_{AA}	ºR	579.67
Daily Average Liquid Surface Temp.	T_{LA}	ºR	579.67
Daily Maximum Liquid Surface Temp.	T_{LX}	ºR	579.67
Daily Minimum Liquid Surface Temp.	T_{LN}	ºR	579.67
Daily Vapor Temperature Range	DT_V	ºR	8.70
Vapor Pressure @ T_{LX}[2]	P_{VX}	psia	5.335
Turnover Factor	K_N		1.0
Working Loss Product Factor	K_P		1.0
Percent of Vapors that are VOC		%	100.0%
Maximum Hourly Emission Rate	L_W	**lb/hr**	**0.11**

Speciated Maximum Hourly Emissions		
Component[2]	**Weight % in Vapor Phase**	**Speciated Emissions (lb/hr)**
Nitrogen	0.00%	0.000
CO_2	0.00%	0.000
Methane	0.00%	0.000
Ethane	0.00%	0.000
Propane	0.00%	0.000
i-Butane	0.00%	0.000
n-Butane	0.00%	0.000
i-Pentane	0.00%	0.000
n-Pentane	0.00%	0.000
n-Hexane	71.74%	0.080
Benzene	7.44%	0.008
n-Heptane	17.66%	0.020
Toluene	2.48%	0.003
E-Benzene	0.25%	0.000
p-Xylene	0.44%	0.000
H_2O	0.00%	0.000
COS	0.00%	0.000
H2S	0.00%	0.000
M-Mercaptan	0.00%	0.000
E-Mercaptan	0.00%	0.000
nPMercaptan	0.00%	0.000
nBMercaptan	0.00%	0.000
ThermialB_1	0.00%	0.000
Oxygen	0.00%	0.000
Argon	0.00%	0.000
CO	0.00%	0.000
MDEA	0.00%	0.000
Piperazine	0.00%	0.000
Total VOC Emissions (lb/hr):		**0.112**
Total HAP Emissions (lb/hr):		**0.092**

[1] The daily solar insolation factor and daily ambient temperature are for Houston, TX in the month of July (July factors are used to calculate maximum hourly emissions).

[2] The vapor pressure and component speciation profile was obtained from the vapor mass fraction calculated using TANKS 4.09d at a temperature of 120°F.

ATTACHMENT C

SUPPORT DOCUMENTATION

Dow UCARSOL Product Technical Information

Dow UCARSOL MSDS

Radco Hot Oil MSDS

Zeeco Burner Data Sheet for Process Heaters

Inlet Feed Composition

Solar Centaur 40 Data Sheet

Solar Centaur 40 Predicted Engine Performance Document

Dow Ucarsol Product Technical Information

Gas Treating Products & Services

UCARSOL AP 814 Solvent For CO_2 Removal

Introduction

UCARSOL™ AP 814 Solvent is one in a series of advanced-performance gas treating solvents from The Dow Chemical Company. Specifically designed for carbon dioxide (CO_2) removal in natural and synthesis gas processing, UCARSOL AP 814 Solvent is effective in both sweet and sour gas streams.

Low heats of reaction, combined with the ability to remove both CO_2 and H_2S, allow the gas processor to conform to current environmental regulations concerning sulfur emissions, while meeting product gas BTU specifications. UCARSOL AP 814 Solvent is particularly useful for processing feed gas with high amounts of carbon dioxide. It performs well in cryogenic applications with low CO_2 product gas specifications.

Special Features

UCARSOL AP 814 Solvent offers these important advantages versus generic gas treating solutions:

- Significant energy savings through reduced reboiler duty, decreased pumping requirements because of lower solvent circulation, and elimination of the need for solvent reclaiming.
- Reduced solvent losses because of low foaming tendency and lower solvent vapor pressure.
- Increased acid gas processing ability with existing facilities.
- Local technical support and complete solvent services available to assure ongoing trouble- free operation.
- Supported by The Dow Chemical Company, the global leader in providing gas treating processors with specialized technology and services.

Corrosion Effects

The results of actual field experience in numerous operating units indicate that solutions of UCARSOL AP 814 solvent, maintained properly and used as specified, exhibit very low corrosion rates. See "Storage and Handling" for effects on other materials.

Physical Properties

UCARSOL AP 814 solvent can be used as aqueous solutions in various concentrations; however, a 50% aqueous solution has been found to offer the optimum performance. Physical property data for pure and 50% aqueous solutions of UCARSOL AP 814 solvent have been developed and are presented on the following pages.

Additional information on UCARSOL AP 814 solvent, its properties and advantages, is available on request. To explore more specifically what UCARSOL AP 814 solvent can do for your existing or proposed gas treating unit, contact Dow at the numbers listed on the back of this brochure.

Table 1 Physical Properties of UCARSOL AP 814 Solvent

	Value
Average Weight per Gallon at 20°C, lb	8.73
Average Weight per Liter at 20°C, kg	1.05
D lb per Gallon/D at 20°C	0.00644
D kg per Liter/D at 20°C	0.00077
Coefficient of Thermal Expansion Per °C (est)	
at 20°C	0.00073
at 55°C	0.00078
Boiling Point, °C (°F)	
at 760 mm Hg	125.9 (258.6)
at 50 mm Hg	60.1 (141.1)
at 10 mm Hg	32.0 (89.7)
Pour Point, °C (°F)	-48 (-54.4)
pH at ambient conditions	11.2
Specific Gravity, 20°/20°C	1.0448
Solubility	
in Water at 20°C, weight percent	100
of Water in at 20°C, weight percent	100
Flash Point, °C (°F)	
Pensky-Martens Closed Cup, ASTM D93,	102 (215)
Cleveland Open Cup, ASTM D92	132 (270)

Table 2 Physical Properties of 50 Percent by Weight Aqueous UCARSOL AP 814 Solvent

	Value
Boiling Point, °C (°F)	103.6 (218.6)
at 760 mm Hg	41.3 (106.3)
at 50 mm Hg	14.6 (58.3)
at 10 mm Hg	
Freezing Point, °C (°F)†	4.2 (39.5)
pH at ambient conditions	11.2
Specific Gravity, 20/20°C	1.04352
Solubility	
in Water at 20°C, weight percent	100
of Water in at 20°C, weight percent	100

†Slurry formation (two-phase freeze separation) may begin at 4°C (40°F). This slurry is pumpable down to -11°C (12°F) in most cases.

Gas Treating Services

Dow is the worldwide leader in providing gas treating processors with specialized technology and services. To aid in both plant design and operation, UCARSOL solvents are supported by advanced computer capabilities, state-of-the-art laboratory, field test equipment, analytical procedures, and an ongoing optimization program. The services Dow provides encompass preliminary assessments, start-up services, continual monitoring, and follow-up services. Included in this total support program are training for your people in the field, regular sample testing, and performance evaluation. To ensure complete customer protection and satisfaction, Dow is there every step of the way-before, during, and after installation.

Computer Capabilities

With information drawn from the actual operating conditions of over 350 plants, Dow has the largest formulated solvents database in the industry.

Dow's sophisticated computer programs provide a powerful tool for process analysis and design, including tray-by-tray calculations. Hydraulic evaluations can be made of existing trayed or packed towers to ensure that conversion to UCARSOL solvents will be trouble-free.

Field representatives have laptop computers that can be taken into a customer's plant, making it possible to predict the performance of UCARSOL solvents under actual plant conditions. In addition to its use as an in-field preliminary design tool, the laptop computer is extremely valuable after conversion to make any adjustments necessary to optimize the process.

Laboratory and Field Testing

Dow's Analytical Services Laboratory performs regular service analyses of customer solvents to ensure good performance of the amine unit, as well as specialized analyses to assist in trouble-free operation. Among the routine analyses performed are ion chromatography, atomic absorption, and solution alkalinity. Specialized analyses include gas chromatography/mass spectroscopy, FTIR (Fourier Transform Infra Red), ICP (Inductively Coupled Plasma Spectroscopy), NMR (Nuclear Magnetic Resonance Spectroscopy), and x-ray fluorescence. Analyses are normally completed and reported to the customer within a few days. Dow's written report usually includes a technical service interpretation of the analytical results and their impact on the customer's operation.

Sample Kits

Dow offers a unique sample kit. Completely self-contained, the kit provides everything necessary-from containers to labels-to obtain lean amine samples, seal them, and safely ship them for routine analysis.

Other Services

Dow's engineering expertise is also available to provide information on process and equipment requirements, and Dow's corrosion group can assist in field inspections or set up corrosion-monitoring programs for customers. Also, Dow trains customer personnel prior to and during conversion and works with them to ensure optimum performance.

Figure 1 Density of Aqueous UCARSOL AP 814 Solvent Solutions

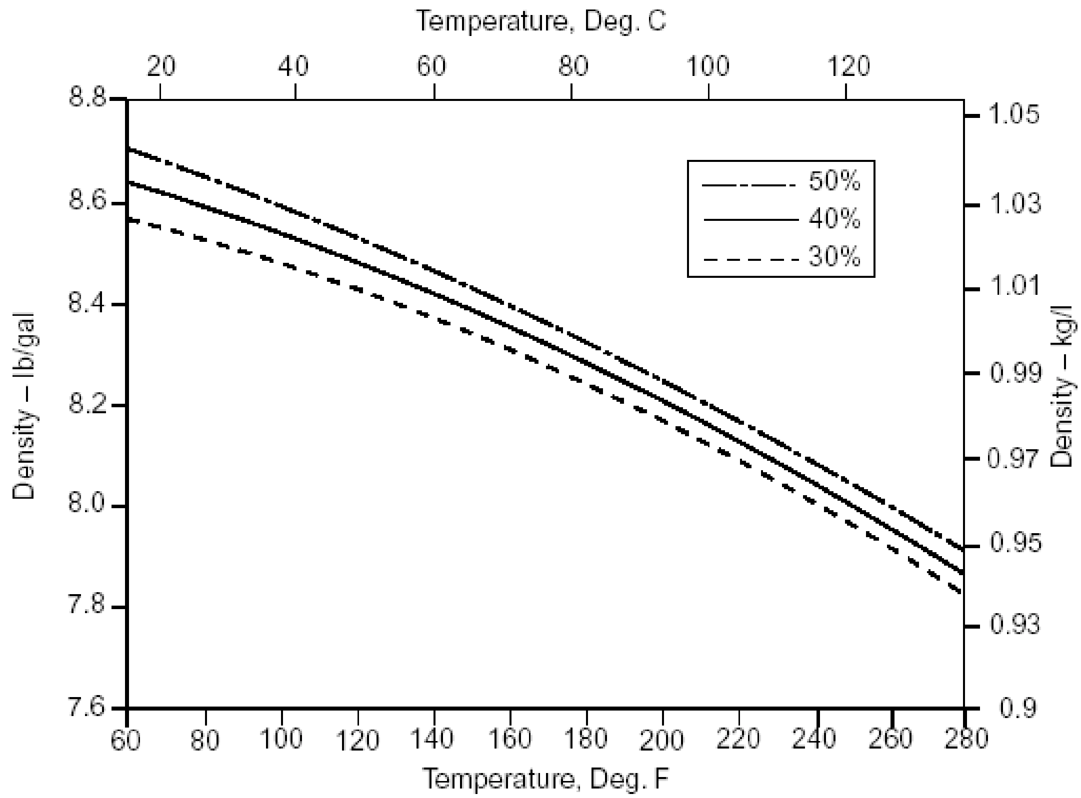


Figure 2 Viscosity of Aqueous UCARSOL AP 814 Solvent Solutions

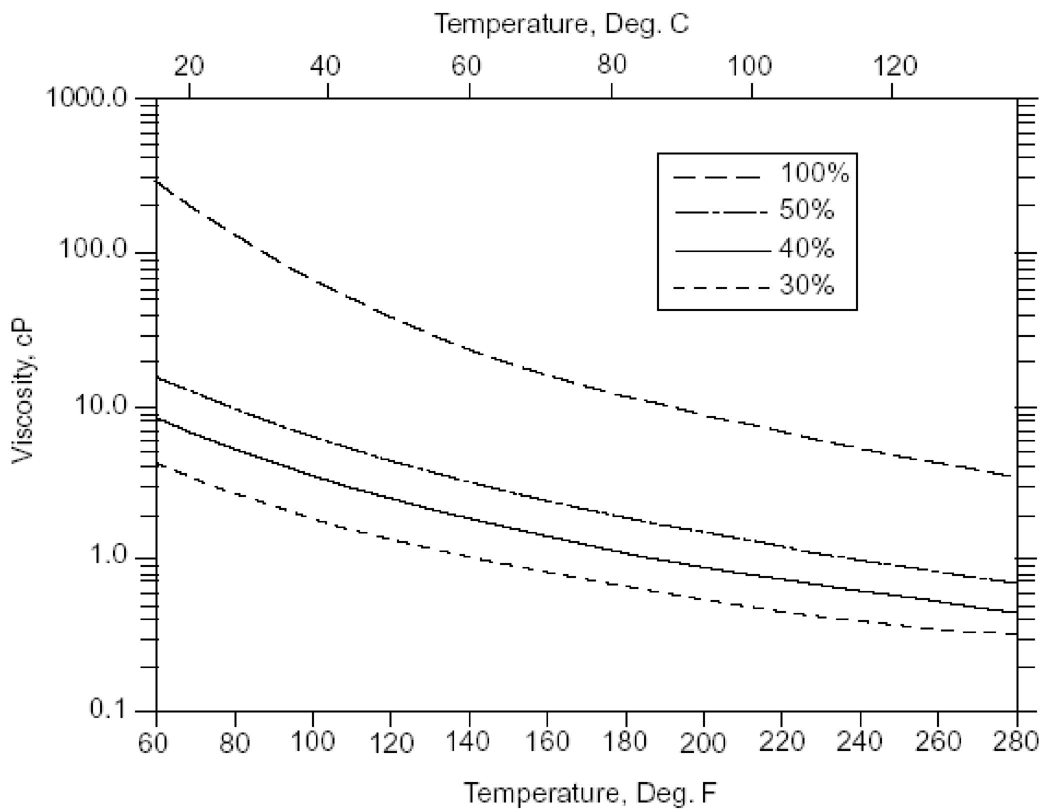


Figure 3 Specific Heat of Aqueous UCARSOL AP 814 Solvent Solutions

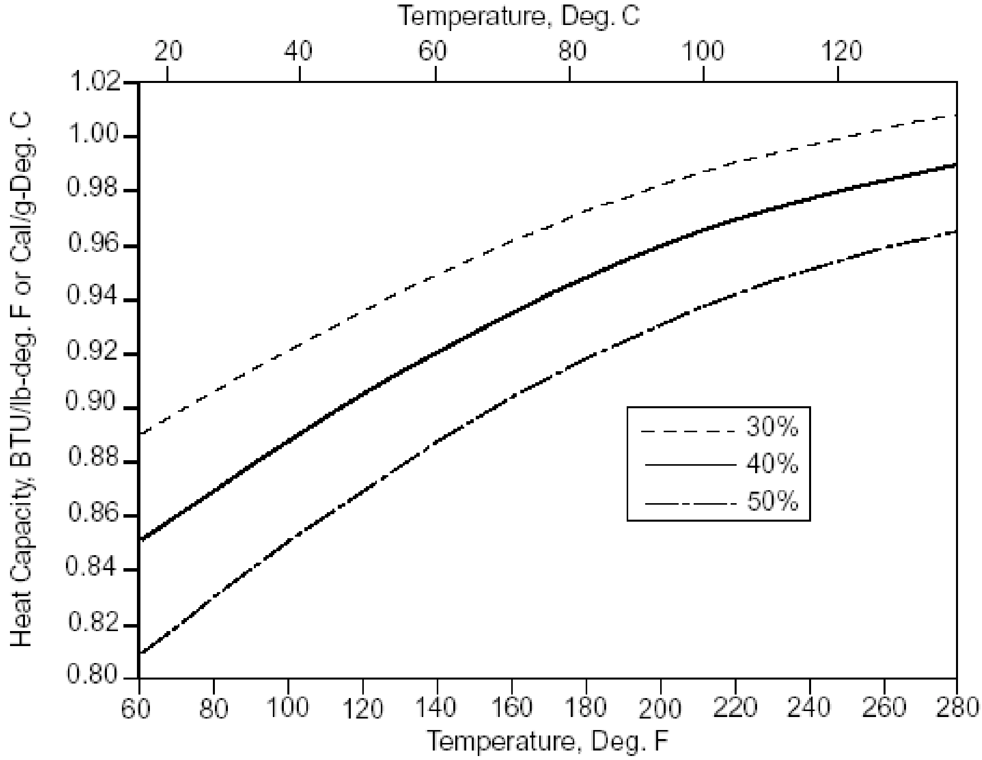


Figure 4 Thermal Conductivity of Aqueous UCARSOL AP 814 Solvent Solutions

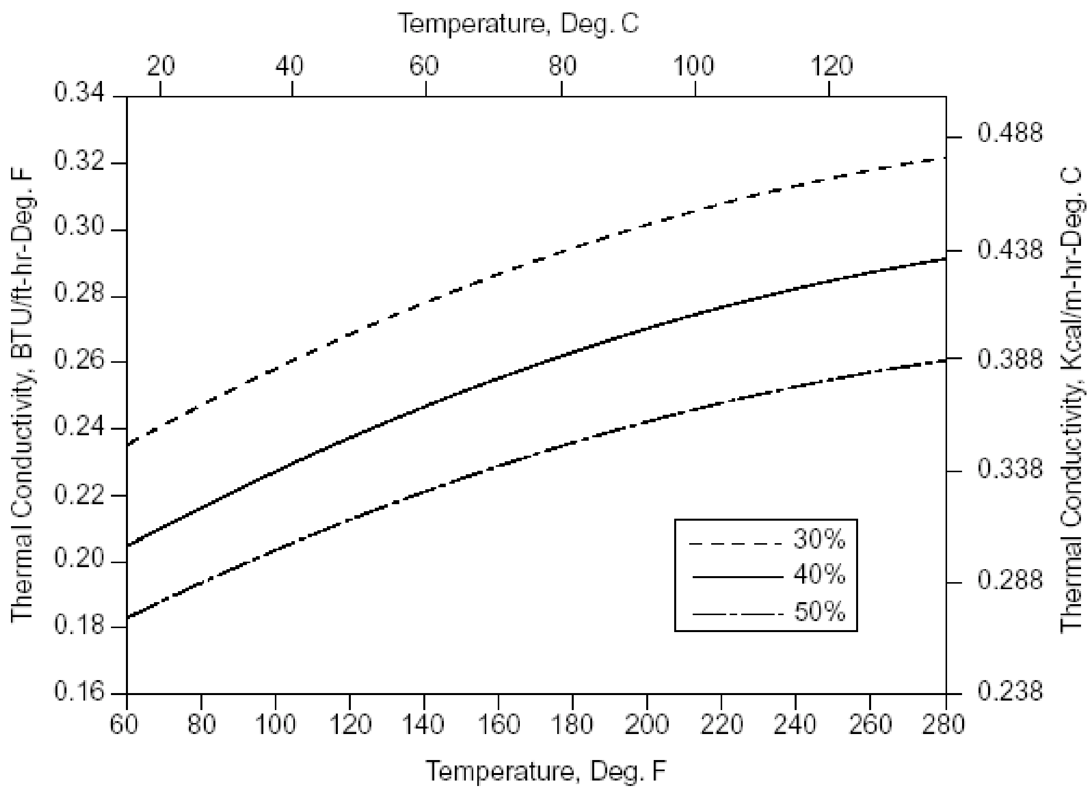
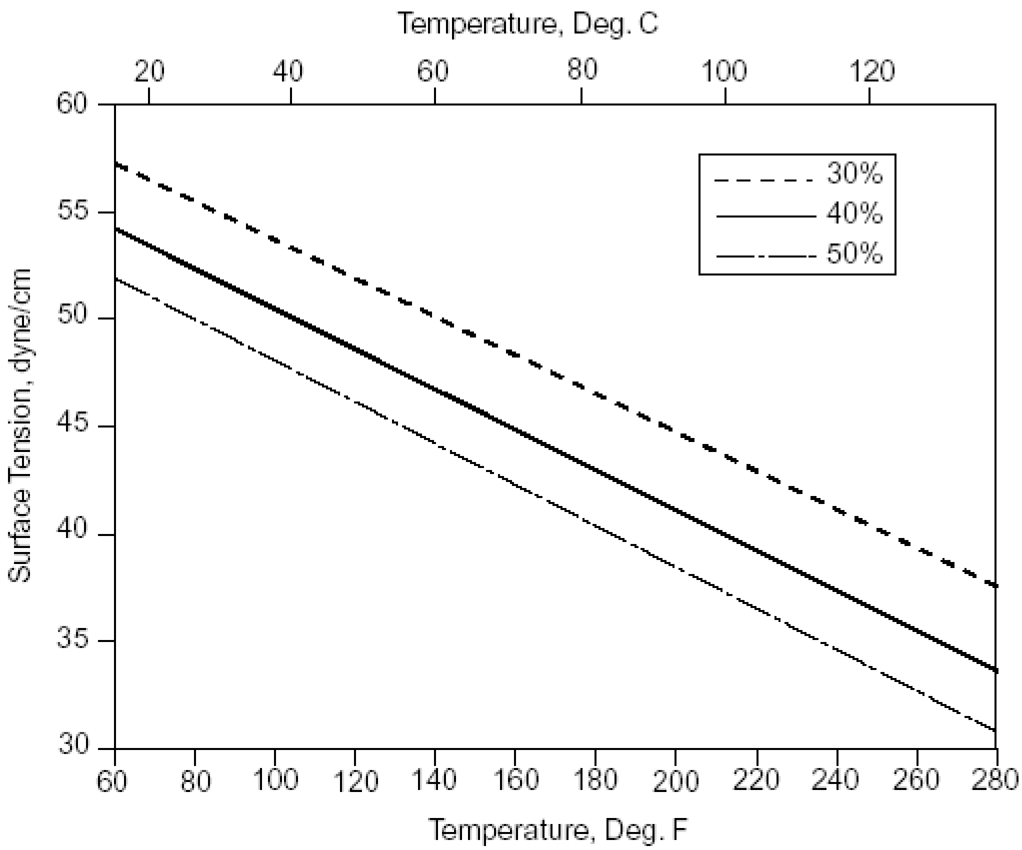


Figure 5 Surface Tension of Aqueous UCARSOL AP 814 Solvent Solutions



Storage and Handling

UCARSOL AP 814 solvent is usually stored and handled in carbon steel equipment. It is also compatible with stainless steel. **Zinc or galvanized steel and copper and its alloys should not be used.**

This product becomes viscous at outside winter temperatures and has a pour point of -48°C (-54.4°F). Therefore, storage inside a warm building or in a heated, insulated tank may be desirable. A centrifugal pump is suitable for transfer service, assuming the temperature of the product is sufficiently above its pour point. A rotary or gear pump is suggested for lower temperature transfers.

Piping should be of adequate size to handle the maximum viscosity expected to be encountered. Valves, piping, etc., are usually of steel construction. Type 304 stainless steel, spiral wound GRAFOIL™gaskets for flanges and GRAFOIL packing for valves is recommended.

Aqueous solutions of UCARSOL AP 814 solvent can be handled in steel equipment. They should **not** be handled or stored in contact with aluminum, zinc, or galvanized iron, or copper and its alloys.

Product Safety

When considering the use of any Dow products in a particular application, you should review Dow's latest Material Safety Data Sheets and ensure that the use you intend can be accomplished safely. For Material Safety Data Sheets and other product safety information, contact Dow at the numbers listed below. Before handling any other products mentioned in the text, you should obtain available product safety information and take necessary steps to ensure safety of use.

No chemical should be used as or in a food, drug, medical device or cosmetic, or in a product or process in which it may contact a food, drug, medical device or cosmetic until the user has determined the suitability and legality of the use. Since government regulations and use conditions are subject to change, it is the user's responsibility to determine that this information is appropriate and suitable under current, applicable laws and regulations.

Dow requests that the customer read, understand, and comply with the information contained in this publication and the current Material Safety Data Sheet(s). The customer should furnish the information in this publication to its employees, contractors and customers, or any other users of the product(s), and request that they do the same.

To Learn More:
The Dow Chemical Company
Midland, Michigan 48674 U.S.A.

For More Information

In the United States: call toll-free 1-800-447-4369 or 1-800-UCARSOL ● fax 1-989-832-1465
In Canada: call toll-free 1-800-447-4369 ● call 1-403-267-3508 ● fax 1-989-832-1465
In Northern Europe and Scandinavia: call +32 89 51 1022 ● fax +32 89 51 0012
In Southern and Eastern Europe, Russia, Middle East, Africa, India and Pakistan:
call +49 7227 91 3814 ● fax +49 7227 91 3808
In the Pacific (except China): call toll-free +800 7776-7776 ● fax toll-free +800 7779-7779
In China: call toll-free +10 800 600-0015 ● fax toll-free +10 800 600-0017
In Singapore: call (65) 6830-4651 ● fax (65) 6834-0320
In Japan: call +81-3-5460-2193 ● fax +81-3-5460-6246
In South and Latin America: call 55 11 5188 9555 ● fax 55 11 5188 9400
In Mexico: call 01 52 55 5201 4700 ● fax 01 52 5 201 4723
In Other Global Areas: call 1-989-832-1560 ● fax 1-989-832-1465 (USA)

Or visit us at www.dowgastreating.com

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Published July 2004.

Form No. 111-01371-0704

Dow Ucarsol MSDS

The Dow Chemical Company encourages and expects you to read and understand the entire (M)SDS, as there is important information throughout the document. We expect you to follow the precautions identified in this document unless your use conditions would necessitate other appropriate methods or actions.

1. Product and Company Identification

Product Name
UCARSOL(TM) AP SOLVENT 814

COMPANY IDENTIFICATION
The Dow Chemical Company
2030 Willard H. Dow Center
Midland, MI 48674
USA

Customer Information Number: 800-258-2436

EMERGENCY TELEPHONE NUMBER
24-Hour Emergency Contact: 989-636-4400
Local Emergency Contact: 989-636-4400

2. Hazards Identification

Emergency Overview
Color: Yellow
Physical State: Liquid
Odor: Ammoniacal
Hazards of product:

> DANGER! Causes severe eye burns. Causes burns of the mouth and throat. Prolonged exposure may cause skin burns. May cause allergic skin reaction. May be harmful if swallowed. Aspiration hazard. Can enter lungs and cause damage. Evacuate area. Keep upwind of spill. Stay out of low areas.

OSHA Hazard Communication Standard
This product is a "Hazardous Chemical" as defined by the OSHA Hazard Communication Standard, 29 CFR 1910.1200.

Potential Health Effects
Eye Contact: May cause severe irritation with corneal injury which may result in permanent impairment of vision, even blindness. Chemical burns may occur.

Skin Contact: Prolonged contact may cause skin burns. Symptoms may include pain, severe local redness, swelling, and tissue damage.
Skin Absorption: Prolonged skin contact is unlikely to result in absorption of harmful amounts.
Skin Sensitization: Skin contact may cause an allergic skin reaction. Contains component(s) which caused allergic skin reactions when tested in mice. Individuals who have had an allergic skin reaction to similar materials may have an allergic skin reaction to this product. The similar material(s) is/are: Triethylenetetramine (TETA).
Inhalation: At room temperature, exposure to vapor is minimal due to low volatility. If material is heated or aerosol/mist is produced, concentrations may be attained that are sufficient to cause respiratory irritation and other effects. Asthma-like symptoms may include coughing, difficult breathing and a feeling of tightness in the chest. Occasionally, breathing difficulties may be life threatening.
Ingestion: Low toxicity if swallowed. Swallowing may result in burns of the mouth and throat. Swallowing may result in gastrointestinal irritation or ulceration. May cause nausea and vomiting. May cause abdominal discomfort or diarrhea.
Aspiration hazard: Aspiration into the lungs may occur during ingestion or vomiting, causing tissue damage or lung injury.
Birth Defects/Developmental Effects: For the minor component(s): Has caused birth defects in laboratory animals only at doses toxic to the mother. Has been toxic to the fetus in laboratory animals at doses toxic to the mother.
Reproductive Effects: For the minor component(s): In animal studies, has been shown to interfere with reproduction. In animal studies, has been shown to interfere with fertility.

3. Composition Information

Component	CAS #	Amount
Substituted amine (1)	Trade secret	> 65.0 %
Substituted amine (2)	Trade secret	> 15.0 %
Water	7732-18-5	7.0 - 9.0 %

4. First-aid measures

Eye Contact: Wash immediately and continuously with flowing water for at least 30 minutes. Remove contact lenses after the first 5 minutes and continue washing. Obtain prompt medical consultation, preferably from an ophthalmologist.
Skin Contact: Immediately wash skin with soap and plenty of water for at least 15 minutes while removing contaminated clothing and shoes. Obtain medical attention without delay. Wash clothing before reuse. Destroy contaminated articles such as shoes. Discard items which cannot be decontaminated, including leather articles such as shoes, belts and watchbands.
Inhalation: Move person to fresh air. If not breathing, give artificial respiration; if by mouth to mouth use rescuer protection (pocket mask, etc). If breathing is difficult, oxygen should be administered by qualified personnel. Call a physician or transport to a medical facility.
Ingestion: Do not induce vomiting. Call a physician and/or transport to emergency facility immediately. If vomiting occurs naturally, have victim lean forward to reduce risk of aspiration.
Notes to Physician: Do not induce vomiting. Give one cup (8 ounces or 240 ml) of water or milk if available and transport to a medical facility. Do not give anything by mouth to an unconscious person. Chemical eye burns may require extended irrigation. Obtain prompt consultation, preferably from an ophthalmologist. Maintain adequate ventilation and oxygenation of the patient. May cause respiratory sensitization or asthma-like symptoms. Bronchodilators, expectorants and antitussives may be of help. Treat bronchospasm with inhaled beta2 agonist and oral or parenteral corticosteroids. Due to irritant properties, swallowing may result in burns/ulceration of mouth, stomach and lower gastrointestinal tract with subsequent stricture. Aspiration of vomitus may cause lung injury. Suggest endotracheal/esophageal control if lavage is done. If burn is present, treat as any thermal burn, after decontamination. No specific antidote. Treatment of exposure should be directed at the control of symptoms and the clinical condition of the patient.

Medical Conditions Aggravated by Exposure: Excessive exposure may aggravate preexisting asthma and other respiratory disorders (e.g. emphysema, bronchitis, reactive airways dysfunction syndrome).

5. Fire Fighting Measures

Extinguishing Media: Water fog or fine spray. Dry chemical fire extinguishers. Carbon dioxide fire extinguishers. Foam. Do not use direct water stream. May spread fire. Alcohol resistant foams (ATC type) are preferred. General purpose synthetic foams (including AFFF) or protein foams may function, but will be less effective.
Fire Fighting Procedures: Keep people away. Isolate fire and deny unnecessary entry. Burning liquids may be extinguished by dilution with water. Do not use direct water stream. May spread fire. Burning liquids may be moved by flushing with water to protect personnel and minimize property damage.
Special Protective Equipment for Firefighters: Wear positive-pressure self-contained breathing apparatus (SCBA) and protective fire fighting clothing (includes fire fighting helmet, coat, trousers, boots, and gloves). Avoid contact with this material during fire fighting operations. If contact is likely, change to full chemical resistant fire fighting clothing with self-contained breathing apparatus. If this is not available, wear full chemical resistant clothing with self-contained breathing apparatus and fight fire from a remote location. For protective equipment in post-fire or non-fire clean-up situations, refer to the relevant sections.
Unusual Fire and Explosion Hazards: Violent steam generation or eruption may occur upon application of direct water stream to hot liquids.
Hazardous Combustion Products: During a fire, smoke may contain the original material in addition to combustion products of varying composition which may be toxic and/or irritating. Combustion products may include and are not limited to: Nitrogen oxides. Carbon monoxide. Carbon dioxide.

6. Accidental Release Measures

Steps to be Taken if Material is Released or Spilled: Small spills: Absorb with materials such as: Non-combustible material. Clay. Vermiculite. Zorb-all®. Do NOT use absorbent materials such as: Ground corn cobs. Moist organic absorbents. Peat moss. Cellulose. Sawdust. Large spills: Contain spilled material if possible. Collect in suitable and properly labeled containers. See Section 13, Disposal Considerations, for additional information.
Personal Precautions: Evacuate area. Refer to Section 7, Handling, for additional precautionary measures. Keep upwind of spill. Ventilate area of leak or spill. Keep personnel out of low areas. Only trained and properly protected personnel must be involved in clean-up operations. Use appropriate safety equipment. For additional information, refer to Section 8, Exposure Controls and Personal Protection.
Environmental Precautions: Prevent from entering into soil, ditches, sewers, waterways and/or groundwater. See Section 12, Ecological Information.

7. Handling and Storage

Handling

General Handling: Do not get in eyes. Do not swallow. Avoid breathing vapor. Avoid contact with skin and clothing. Avoid prolonged or repeated contact with skin. Wash thoroughly after handling. Keep container closed. Use with adequate ventilation. Do not use sodium nitrite or other nitrosating agents in formulations containing this product. Suspected cancer-causing nitrosamines could be formed. See Section 8, EXPOSURE CONTROLS AND PERSONAL PROTECTION.
Other Precautions: Spills of these organic materials on hot fibrous insulations may lead to lowering of the autoignition temperatures possibly resulting in spontaneous combustion.

Storage

Store in accordance with good manufacturing practices. Use only with adequate ventilation. Do not store in: Aluminum. Copper. Copper alloys. Galvanized containers. Zinc. Additional storage and handling information on this product may be obtained by calling your sales or customer service contact.

Storage Period:
Bulk
18 Months
Metal drums.
36 Months

8. Exposure Controls / Personal Protection

Exposure Limits

Component	List	Type	Value

None established

Personal Protection

Eye/Face Protection: Use chemical goggles. Eye wash fountain should be located in immediate work area.
Skin Protection: Use protective clothing chemically resistant to this material. Selection of specific items such as face shield, boots, apron, or full body suit will depend on the task. Remove contaminated clothing immediately, wash skin area with soap and water, and launder clothing before reuse or dispose of properly. Items which cannot be decontaminated, such as shoes, belts and watchbands, should be removed and disposed of properly.
Hand protection: Use gloves chemically resistant to this material. Examples of preferred glove barrier materials include: Chlorinated polyethylene. Polyethylene. Ethyl vinyl alcohol laminate ("EVAL"). Examples of acceptable glove barrier materials include: Butyl rubber. Natural rubber ("latex"). Neoprene. Nitrile/butadiene rubber ("nitrile" or "NBR"). Polyvinyl chloride ("PVC" or "vinyl"). Viton. Avoid gloves made of: Polyvinyl alcohol ("PVA"). NOTICE: The selection of a specific glove for a particular application and duration of use in a workplace should also take into account all relevant workplace factors such as, but not limited to: Other chemicals which may be handled, physical requirements (cut/puncture protection, dexterity, thermal protection), potential body reactions to glove materials, as well as the instructions/specifications provided by the glove supplier.
Respiratory Protection: Respiratory protection should be worn when there is a potential to exceed the exposure limit requirements or guidelines. If there are no applicable exposure limit requirements or guidelines, use an approved respirator. Selection of air-purifying or positive-pressure supplied-air will depend on the specific operation and the potential airborne concentration of the material. For emergency conditions, use an approved positive-pressure self-contained breathing apparatus. The following should be effective types of air-purifying respirators: Organic vapor cartridge with a particulate pre-filter.
Ingestion: Avoid ingestion of even very small amounts; do not consume or store food or tobacco in the work area; wash hands and face before smoking or eating.

Engineering Controls

Ventilation: Use engineering controls to maintain airborne level below exposure limit requirements or guidelines. If there are no applicable exposure limit requirements or guidelines, use only with adequate ventilation. Local exhaust ventilation may be necessary for some operations.

9. Physical and Chemical Properties

Physical State	Liquid
Color	Yellow
Odor	Ammoniacal
Flash Point - Closed Cup	102 °C (216 °F) *ASTM D93*
Flash Point - Open Cup	132 °C (270 °F) *Cleveland Open Cup ASTM D92*

Flammable Limits In Air	**Lower**: No test data available **Upper**: No test data available
Autoignition Temperature	304 - 307 °C (579 - 585 °F)
Vapor Pressure	4.6 mmHg @ 20 °C
Boiling Point (760 mmHg)	126 °C (259 °F) .
Vapor Density (air = 1)	2.8
Specific Gravity (H2O = 1)	1.045 20 °C/20 °C
Freezing Point	-48 °C (-54 °F) Pour point
Melting Point	Not applicable
Solubility in Water (by weight)	100 % @ 20 °C
pH	11
Decomposition Temperature	No test data available
Evaporation Rate (Butyl Acetate = 1)	0.5
Kinematic Viscosity	No test data available

10. Stability and Reactivity

Stability/Instability
Stable under recommended storage conditions. See Storage, Section 7.
Conditions to Avoid: Exposure to elevated temperatures can cause product to decompose.

Incompatible Materials: Avoid contact with: Acrylates. Alcohols. Aldehydes. Ketones. Nitrites. Strong acids. Strong oxidizers. Avoid contact with metals such as: Aluminum. Copper. Copper alloys. Galvanized metals. Zinc. Avoid unintended contact with: Halogenated hydrocarbons. Avoid contact with absorbent materials such as: Ground corn cobs. Moist organic absorbents. Peat moss. Sawdust.

Hazardous Polymerization
Will not occur.

Thermal Decomposition
Decomposition products depend upon temperature, air supply and the presence of other materials.

11. Toxicological Information

Acute Toxicity
Ingestion
Single dose oral LD50 has not been determined.
Skin Absorption
The dermal LD50 has not been determined.

Sensitization
Skin
Skin contact may cause an allergic skin reaction. Contains component(s) which caused allergic skin reactions when tested in mice. Individuals who have had an allergic skin reaction to similar materials may have an allergic skin reaction to this product. The similar material(s) is/are: Triethylenetetramine (TETA).

Repeated Dose Toxicity
For the component(s) tested: Based on available data, repeated exposures are not anticipated to cause additional significant adverse effects.

Chronic Toxicity and Carcinogenicity
For the minor component(s): Did not cause cancer in laboratory animals.

Developmental Toxicity

For the minor component(s): Has caused birth defects in laboratory animals only at doses toxic to the mother. Has been toxic to the fetus in laboratory animals at doses toxic to the mother. For the major component(s): Did not cause birth defects or other effects in the fetus even at doses which caused toxic effects in the mother.

Reproductive Toxicity

For the minor component(s): In animal studies, has been shown to interfere with reproduction. In animal studies, has been shown to interfere with fertility.

Genetic Toxicology

For all components. In vitro genetic toxicity studies were negative. For all components. Animal genetic toxicity studies were negative.

12. Ecological Information

ENVIRONMENTAL FATE

Data for Component: **Substituted amine (1)**

Movement & Partitioning

Bioconcentration potential is low (BCF less than 100 or log Pow less than 3). Potential for mobility in soil is very high (Koc between 0 and 50).
Henry's Law Constant (H): 1.07E-06 atm*m3/mole; 25 °C Estimated
Partition coefficient, n-octanol/water (log Pow): < 0.2 Measured
Partition coefficient, soil organic carbon/water (Koc): 1 Estimated

Persistence and Degradability

Material is readily biodegradable. Passes OECD test(s) for ready biodegradability. Material is ultimately biodegradable (reaches > 70% mineralization in OECD test(s) for inherent biodegradability).

Indirect Photodegradation with OH Radicals

Rate Constant	Atmospheric Half-life	Method
9.70E-11 cm3/s	1.324 h	

OECD Biodegradation Tests:

Biodegradation	Exposure Time	Method
96 %	18 d	OECD 301A Test
94 %	7 d	OECD 302B Test

Biological oxygen demand (BOD):

BOD 5	BOD 10	BOD 20	BOD 28
40 %			42 %

Theoretical Oxygen Demand: 2.29 mg/mg

Data for Component: **Substituted amine (2)**

Movement & Partitioning

Bioconcentration potential is low (BCF less than 100 or log Pow less than 3). Potential for mobility in soil is very high (Koc between 0 and 50).
Henry's Law Constant (H): 2.50E-06 atm*m3/mole; 25 °C Estimated
Partition coefficient, n-octanol/water (log Pow): -1.50 Measured
Partition coefficient, soil organic carbon/water (Koc): < 1 Estimated
Bioconcentration Factor (BCF): < 3.9; fish; Measured

Persistence and Degradability

Material is ultimately biodegradable (reaches > 70% mineralization in OECD test(s) for inherent biodegradability). Material is expected to biodegrade only very slowly (in the environment). Fails to pass OECD/EEC tests for ready biodegradability.

Indirect Photodegradation with OH Radicals

Rate Constant	Atmospheric Half-life	Method
1.69E-10 cm3/s	0.76 h	Estimated

OECD Biodegradation Tests:

Biodegradation	Exposure Time	Method
> 90 %	28 d	OECD 302B Test

1.4 %	14 d	OECD 301C Test

Biological oxygen demand (BOD):

BOD 5	BOD 10	BOD 20	BOD 28
		3.6 %	

Chemical Oxygen Demand: 1.97 mg/mg
Theoretical Oxygen Demand: 3.35 mg/mg

ECOTOXICITY

Data for Component: **Substituted amine (1)**

Material is slightly toxic to aquatic organisms on an acute basis (LC50/EC50 between 10 and 100 mg/L in the most sensitive species tested).

Fish Acute & Prolonged Toxicity
LC50, fathead minnow (Pimephales promelas), static, 96 h: 1,200 mg/l
Aquatic Invertebrate Acute Toxicity
LC50, water flea Daphnia magna, static, 48 h, immobilization: 250 mg/l
LC50, copepod Acartia tonsa: 84 mg/l
Aquatic Plant Toxicity
EC50, diatom Skeletonema costatum, static, biomass growth inhibition, 72 h: 73 mg/l

Data for Component: **Substituted amine (2)**

Material is slightly toxic to fish on an acute basis (LC50 between 10 and 100 mg/L).

Fish Acute & Prolonged Toxicity
LC50, fathead minnow (Pimephales promelas): 200 - 500 mg/l
Aquatic Invertebrate Acute Toxicity
LC50, water flea Daphnia magna, 48 h: 98.1 mg/l
Toxicity to Micro-organisms
IC50; bacteria, Growth inhibition, 16 h: > 5,000 mg/l

13. Disposal Considerations

DO NOT DUMP INTO ANY SEWERS, ON THE GROUND, OR INTO ANY BODY OF WATER. All disposal practices must be in compliance with all Federal, State/Provincial and local laws and regulations. Regulations may vary in different locations. Waste characterizations and compliance with applicable laws are the responsibility solely of the waste generator. AS YOUR SUPPLIER, WE HAVE NO CONTROL OVER THE MANAGEMENT PRACTICES OR MANUFACTURING PROCESSES OF PARTIES HANDLING OR USING THIS MATERIAL. THE INFORMATION PRESENTED HERE PERTAINS ONLY TO THE PRODUCT AS SHIPPED IN ITS INTENDED CONDITION AS DESCRIBED IN MSDS SECTION: Composition Information. FOR UNUSED & UNCONTAMINATED PRODUCT, the preferred options include sending to a licensed, permitted: Incinerator or other thermal destruction device.

14. Transport Information

DOT Non-Bulk
NOT REGULATED

DOT Bulk
NOT REGULATED

IMDG
NOT REGULATED

ICAO/IATA
NOT REGULATED

This information is not intended to convey all specific regulatory or operational requirements/information relating to this product. Additional transportation system information can be obtained through an authorized sales or customer service representative. It is the responsibility of the transporting organization to follow all applicable laws, regulations and rules relating to the transportation of the material.

15. Regulatory Information

OSHA Hazard Communication Standard

This product is a "Hazardous Chemical" as defined by the OSHA Hazard Communication Standard, 29 CFR 1910.1200.

Superfund Amendments and Reauthorization Act of 1986 Title III (Emergency Planning and Community Right-to-Know Act of 1986) Sections 311 and 312

Immediate (Acute) Health Hazard	Yes
Delayed (Chronic) Health Hazard	No
Fire Hazard	No
Reactive Hazard	No
Sudden Release of Pressure Hazard	No

Superfund Amendments and Reauthorization Act of 1986 Title III (Emergency Planning and Community Right-to-Know Act of 1986) Section 313
To the best of our knowledge, this product does not contain chemicals at levels which require reporting under this statute.

Pennsylvania (Worker and Community Right-To-Know Act): Pennsylvania Hazardous Substances List and/or Pennsylvania Environmental Hazardous Substance List:
The following product components are cited in the Pennsylvania Hazardous Substance List and/or the Pennsylvania Environmental Substance List, and are present at levels which require reporting.

Component	CAS #	Amount
Amine	Trade Secret	<= 16.0 %

Pennsylvania (Worker and Community Right-To-Know Act): Pennsylvania Special Hazardous Substances List:
To the best of our knowledge, this product does not contain chemicals at levels which require reporting under this statute.

California Proposition 65 (Safe Drinking Water and Toxic Enforcement Act of 1986)
This product contains no listed substances known to the State of California to cause cancer, birth defects or other reproductive harm, at levels which would require a warning under the statute.

US. Toxic Substances Control Act
All components of this product are on the TSCA Inventory or are exempt from TSCA Inventory requirements under 40 CFR 720.30

CEPA - Domestic Substances List (DSL)
All substances contained in this product are listed on the Canadian Domestic Substances List (DSL) or are not required to be listed.

16. Other Information

Product Literature

Additional information on this product may be obtained by calling your sales or customer service contact. Ask for a product brochure.

Hazard Rating System

NFPA	Health	Fire	Reactivity
	3	1	0

Recommended Uses and Restrictions

Gas treating.

Revision

Identification Number: 1511 / 0000 / Issue Date 12/29/2008 / Version: 4.0
Most recent revision(s) are noted by the bold, double bars in left-hand margin throughout this document.

Legend

N/A	Not available
W/W	Weight/Weight
OEL	Occupational Exposure Limit
STEL	Short Term Exposure Limit
TWA	Time Weighted Average
ACGIH	American Conference of Governmental Industrial Hygienists, Inc.
DOW IHG	Dow Industrial Hygiene Guideline
WEEL	Workplace Environmental Exposure Level
HAZ_DES	Hazard Designation
Action Level	A value set by OSHA that is lower than the PEL which will trigger the need for activities such as exposure monitoring and medical surveillance if exceeded.

Radco Hot Oil MSDS

MATERIAL SAFETY DATA SHEET

I. PRODUCT AND COMPANY IDENTIFICATION

Manufacturer:	Emergency Phone Numbers:
Radco Industries, Inc., PO Box 305 LaFox, IL 60147 USA Emergency Phone: (630) 232-7966 Website: www.Xceltherm.com Product Name: **XCELTHERM® 600** Heat Transfer Fluid Effective Date: 3/17/2004 Revision Date: 9/13/2010	For chemical emergency, spill, leak, fire exposure, accident or medical emergency, call: CHEMTREC North America 1-800-424-9300 International +1 703-527-3887 For shipping emergency or off-hours rush orders call: 1-630-232-7966 or 1-630-336-6728

II. COMPOSITION / INFORMATION ON INGREDIENTS

COMPONENTS	CAS#	CONCENTRATION
Severely hydroprocessed, solvent refined paraffinic white mineral oil	8042-47-5	100%

Severely hydroprocessed paraffinic white mineral oil (CAS 8042-47-5) ACGIH TLV 5mg/m3, STEL 10mg/m3 (oil mist); OSHA PEL 5mg/m3, STEL 10mg/m3 (oil mist)

WARNING STATEMENT

This product has been evaluated and does not require any hazard warning label under the OSHA Hazard Communication Standard.

HMIS/NFPA Codes

Health: 0	Flammability: 1	Reactivity: 0

III. HEALTH HAZARD INFORMATION

EYE

Effect: No significant health hazards identified.
First Aid: Flush eyes with plenty of water.
Protection: None required; however, use of eye protection is good industrial practice.

SKIN

Effect: No significant health hazards identified.
First Aid: None required.
Protection: None required.

INHALATION

Effect: No significant health hazards identified.
First Aid: If adverse effects occur, remove to uncontaminated area. Get medical attention.
Protection: None required; however, use of adequate ventilation is good industrial practice.

INGESTION

Effect: No significant health hazards identified.
First Aid: None required.

IV. Fire and explosion information

Flashpoint (COC): ≥ 380°F (193°C)

Fire Point (COC): ≥ 420°F (216°C)

Autoignition Temperature: ≥ 660°F (349°C)

Extinguishing Media
Agents approved for Class B hazards (e.g., dry chemical, carbon dioxide, halogenated agents, foam, steam) or water fog.

V. REACTIVITY INFORMATION

Dangerous Reactions
None identified.

Hazardous Decomposition
Incomplete burning can produce carbon monoxide and/or carbon dioxide and other harmful products.

Stability
Stable.

VI. CHEMICAL AND PHYSICAL PROPERTIES

Appearance and Odor:	Water-white oily liquid.
Solubility in Water:	Negligible, below 0.1%.
Specific Gravity (Water = 1):	0.80 to 0.88
Viscosity:	95-100 SUS @ 100℉

VII. STORAGE AND ENVIRONMENTAL PROTECTION

Storage Requirements
No special requirements.

Spills and Leaks
Contain on an absorbent material (e.g., sand, sawdust, dirt, clay).

Waste Disposal
Disposal must be in accordance with applicable Federal, State, or Local regulations.

VIII. TOXICOLOGICAL INFORMATION

Eye:
A similar material produced a primary eye irritation score of 1.0/110; 24 hour (rabbit).

Skin:
A similar material produced a primary dermal irritation score of 2.7/8.0. A similar material had a LD50 greater than 2g/kg and was not a skin sensitizer. A similar material produced minimal skin irritation in humans (0.1/12) following five consecutive applications.

Ingestion:
A similar material had a LD50 greater than 5g/kg.

A representative white mineral oil was not carcinogenic to the skin of mice in a two-year study.
Minor changes have been reported in the lungs of animals exposed to mineral oil mist at a concentration of 100mg/m3 for two years. No changes have been detected in animals exposed to oil mist at a concentration of 5mg/m3 or 50mg/m3 for 2 years of 18 months respectively.

No component of this product is identified as a carcinogen by NTP, IARC or OSHA.

IX. REGULATORY INFORMATION

UNITED STATES

CALIFORNIA (Proposition 65 and CARB)
This product does not contain any of the substances known to the State of California to cause cancer, birth defects, or reproductive harm. It also contains no volatile organic compounds (VOC) as defined by the California Air Resources Board (CARB).

IX. REGULATORY INFORMATION continued

CERCLA Reportable Quantity
This product is not reportable under 40 CFR Part 302.4.

DOT Proper Shipping Name
Not regulated.

FDA Status
This product meets or exceeds FDA requirements for direct use in food according to 21 CFR 172.878. It may also be used in products where indirect (incidental) contact with food may occur under 21 CFR 178.3620 and for animal feed under 21 CFR 573.680.

OSHA Hazard Communication Standard
Listed by ACGIH.

RCRA Status
This product is not subject to the 40 CFR Part 268.30 land ban on the disposal of certain hazardous wastes.

SARA Status
This product is not regulated under SARA Title III, 42 USC 9601.

TSCA Status
All of the components of this product are listed on the TSCA inventory.

USDA Status
This product is acceptable to the USDA as a lubricant with incidental
food contact for use in official meat and poultry establishments (H1 Status).

XCELTHERM® 600 contains no Volatile Organic Compounds (VOC) as defined in EPA regulation 40 CFR Part 59, National Volatile Organic Emission Standards for Consumer and Commercial Products.

INTERNATIONAL

AUSTRALIA Inventory (AICS)
Listed on inventory.

CANADA Inventory (DSL)
All the components of this product are listed on the DSL.

EC Inventory (EINECS/ELINCS)
In compliance.

JAPAN Inventory (MITI)
Listed on inventory.

KOREA Inventory (ECL)
Listed on inventory.

PHILLIPPINE Inventory (PICCS)
Listed on inventory.

X. SUPPLEMENTAL INFORMATION

WARNING: “Empty” containers retain residue (liquid and/or vapor) and can be dangerous. Do not pressurize, cut, weld, braze, solder, drill, grind, or expose such containers to heat, flame, sparks, or other sources of ignition; they may explode and cause injury or death. Do not attempt to clean since residue is difficult to remove and even a trace of remaining material constitutes as explosive hazard. “Empty” drums should be completely drained, properly bunged, and promptly returned to a drum recycler. All other containers should be disposed of in an environmentally safe manner and in accordance with governmental regulations.

THIS INFORMATION RELATES TO THE SPECIFIC MATERIAL DESIGNATED AND MAY NOT BE VALID FOR SUCH MATERIAL USED IN COMBINATION WITH ANY OTHER MATERIALS OR IN ANY PROCESS. SUCH INFORMATION STATED IS TO THE BEST OF RADCO=S KNOWLEDGE AND BELIEF, ACCURATE AND RELIABLE AS OF THE DATE COMPILED. HOWEVER, NO REPRESENTATION, WARRANTY OR GUARANTEE IS MADE TO ITS ACCURACY, RELIABILITY, OR COMPLETENESS, AND RADCO DOES NOT ACCEPT LIABILITY FOR ANY LOSS OR DAMAGE THAT MAY OCCUR FROM THE USE OF THIS INFORMATION. FINAL DETERMINATION OF SUITABILITY OF ANY MATERIAL IS THE SOLE RESPONSIBILITY OF THE USER. ALL MATERIAL SHOULD BE USED WITH CAUTION TO GUARD AGAINST UNKNOWN HAZARDS. ALTHOUGH CERTAIN HAZARDS ARE DESCRIBED HEREIN, RADCO DOES NOT GUARANTEE THAT THESE ARE THE ONLY HAZARDS THAT EXIST.

Zeeco Burner Data Sheet for Process Heaters

ZEECO BURNER DATA SHEETS

BASIS OF EMISSIONS INFORMATION

Rev.

Furnace Temperature (°F)	1,481	
Excess Combustion Air (%)	15% Gas	
Combustion Air Temperature (°F)	60	
Relative Humidity (%)	50%	
Heat Release for Guarantee (MM Btu/hr)	3.65	3.20 LHV

EMISSIONS INFORMATION	PREDICTED		GUARANTEED	
	(ppmv)	(#/MMBtu)	(ppmv)	(#/MMBtu)
NOx Natural Gas	19	0.023	25	0.030
CO - Gas	0	0.000	50	0.041
UHC - Gas	1	0.001	15	0.007
Particulate - Gas	2	0.002	15	0.013
VOC - Gas	0	0.000	15	0.019

EMISSIONS COMMENTS

4-1 The above listed UHC emissions are based upon UHC being defined as free "methane" as the result of incomplete combustion due to the supplied combustion equipment as stated in these data sheets.

4-2 The above listed VOC emissions are based upon VOC being defined as free "propane" as the result of incomplete combustion due to the supplied combustion equipment as stated in these data sheets.

4-3 The above listed Particulate emissions are based upon Particulate being defined as free "ethane" as the result of incomplete combustion due to the supplied combustion equipment as stated in these data sheets. This excludes ash, sand and heavy metals in the fuel oil.

4-4 NOx guarantees are based on the furnace temperature, combustion air temperature, excess combustion air and the fuel gas compositions as specified the Zeeco Burner Data Sheets.

4-5 The emissions guarantees above are for operation between maximum and normal heat release.

4-6 The emissions guarantees as stated above are based upon operation with the % excess air, temperature, furnace temperature, and fuel temperatures as stated in these data sheets.

4-7 See Notes & Clarifications section for more information concerning noise emissions.

4-8 See Notes & Clarifications section for more information concerning the above emissions guarantees.

4-9 Zeeco takes exception to any SOx guarantees since SOx production is based upon the amount of Sulfur in the fuel stream and the equilibrium conditions in the furnace.

4-10 The above listed predictions & guarantees are based on the higher heating value 'HHV' of the fuel(s).

4-11 All ppmv and/or mg/Nm3 guarantees are corrected to 3% O2 dry basis.

4-12 All CO, UHC, Particulate and VOC emissions guarantees are based on the furnace local temperature at the burner being above 1100°F (593°C).

ZEECO		2011-EO-051	TBA
	• *Burners*	Optimized Process Furnaces, Inc.	051-1
	• *Flares*	Black & Veatch / DCP	VC
	• *Incinerators*	SE Texas	Rev. A
	• *Combustion Systems*	Round Flame, "Free-Jet"	SHEET 4 OF 5

Inlet Feed Composition

FEEDSTOCKS

1. Feedstocks for this project are available as shown below.

Feed Rate

Feed Rate: 75,000 Std. BPD

Feed Composition (Dry Basis)

	DCP Fractionator Y-Grade Composition		
Component/Characteristic	Light Feed LV%	Average Feed LV%	Heavy Feed LV%
N2	0.00%	0.00%	0.00%
CO2	0.19%	0.16%	0.15%
Methane	0.50%	0.50%	0.50%
Ethane	55.00%	47.00%	42.00%
Propane	23.75%	25.00%	23.00%
i-Butane	5.00%	6.00%	7.00%
n-Butane	9.00%	10.00%	12.00%
i-Pentane	2.00%	3.00%	5.00%
n-Pentane	2.00%	3.00%	4.00%
n-Hexane	1.00%	3.00%	4.00%
Benzene	0.20%	0.20%	0.20%
n-Heptane	1.00%	1.77%	1.78%
Toluene	0.20%	0.20%	0.20%
Ethylbenzene	0.05%	0.05%	0.05%
Xylene	0.10%	0.10%	0.10%
Sulfur Components	0.01%	0.02%	0.02%
Total	100.00%	100.00%	100.00%
Corrosion, Copper Strip	No. 1	No. 1	No. 1
Free Water Content	None	None	None

Feed Sulfur Components

Sulfur Components	Light Feed wt-ppm	Average Feed wt-ppm	Heavy Feed wt-ppm
COS	5	5	5
H2S	2	2	2
M-Mercaptan	57	71	94
E-Mercaptan	88	109	145
N-propyl Mercaptan	35	44	58
N-butyl Mercaptan	3	4	5
Total	190	235	309

Feed Temperature and Pressure

Delivery Pressure: 450 to 500 psig

Delivery Temperature: 50 to 75°F

Solar Centaur 40 Data Sheet

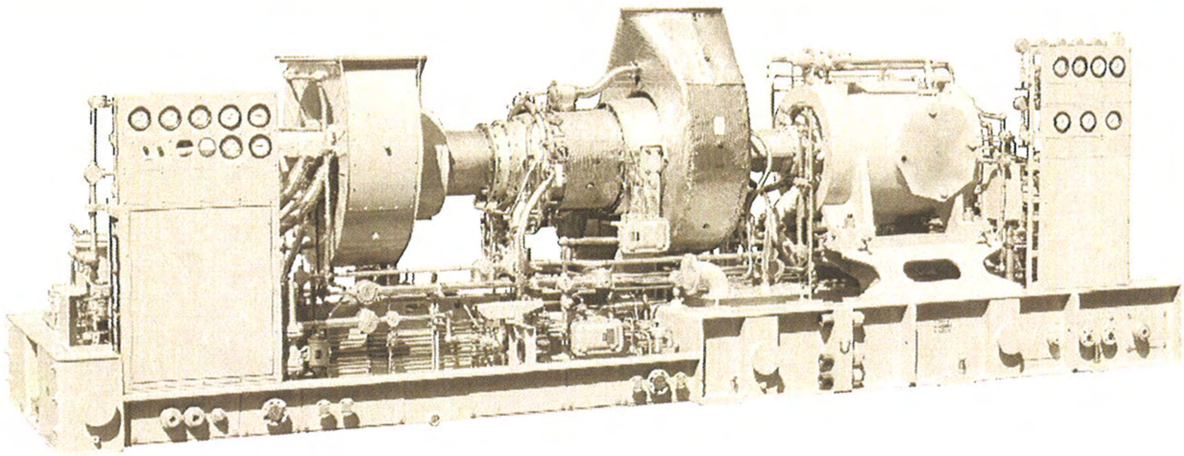
Solar® Turbines

A Caterpillar Company

CENTAUR 40

Gas Turbine Compressor Set

Oil & Gas Applications



General Specifications

***Centaur®* 40 Gas Turbine**

- Industrial, Two-Shaft
- Axial Compressor
  - 11-Stage
  - Variable Inlet Guide Vanes
  - Pressure Ratio: 10.3:1
  - Inlet Airflow: 18.7 kg/sec (41.3 lb/sec)
- Combustion Chamber
  - Annular-Type
  - Conventional or Lean-Premixed, Dry, Low Emission (*SoLoNOx*™)
  - 10 Fuel Injectors (Conventional)
  - 12 Fuel Injectors (*SoLoNOx*)
  - Torch Ignitor System
- Gas Producer Turbine
  - 2-Stage, Reaction
  - Max. Speed: 15,000 rpm
- Power Turbine
  - 1-Stage, Reaction
  - Max. Speed: 15,500 rpm
- Bearings
  - Journal: Tilting-Pad
  - Thrust: Fixed Tapered Land
- Coatings
  - Compressor: Inorganic Aluminum
  - Turbine and Nozzle Blades: Precious Metal Diffusion Aluminide
- Velocity Vibration Transducer

Key Package Features

- Driver Skid with Drip Pans
- Driven Equipment Skid
  - Compressor
  - Compressor Auxiliary Systems
- 316L Stainless Steel Piping ≤4" dia
- Compression-Type Tube Fittings
- Electrical System Options
  - NEC, Class I, Group D, Div 1
  - CENELEC, Zone 1
- *Turbotronic*™ Microprocessor Control System
  - Freestanding Control Console
  - Color Video Display
  - Vibration Monitoring
- Control Options
  - 24-VDC Control Battery/Charger System
  - Package Temperature Monitoring
  - Serial Link Supervisory Interface
  - Turbine Performance Map
  - Compressor Performance Map
  - Historical Displays
  - Printer/Logger
  - Predictive Emissions Monitoring
  - Process Controls
  - Compressor Anti-Surge Control
  - Field Programming
- Start Systems
  - Pneumatic
  - Direct-Drive AC
- Fuel Systems
  - Natural Gas
  - Alternate Fuels
- Integrated Lube Oil System
  - Turbine-Driven Accessories
- Oil System Options
  - Oil Cooler
  - Oil Heater
  - Tank Vent Separator
  - Flame Trap
- Axial Compressor Cleaning Systems
  - On-Crank
  - On-Crank/On-Line
  - Stationary Cleaning Tank
  - Portable Cleaning Tank
- Gearbox (if applicable)
  - Speed Increasers
  - Speed Decreasers
- Air Inlet and Exhaust System Options
- Enclosure and Associated Options
- Factory Testing of Turbine and Package
- Documentation
  - Drawings
  - Quality Control Data Book
  - Inspection and Test Plan
  - Test Reports
  - Operation and Maintenance Manuals

Solar® Turbines
A Caterpillar Company

CENTAUR 40
Gas Turbine Compressor Set

Oil & Gas Applications

Performance

Output Power	3500 kW (4700hp)
Heat Rate	12 905 kJ/kW-hr (9,125 Btu/hp-hr)
Exhaust Flow	68 185 kg/hr (150,320 lb/hr)
Exhaust Temp.	450°C (835°F)

Nominal Rating – per ISO
At 15°C (59°F), at sea level

No inlet/exhaust losses

Relative humidity 60%

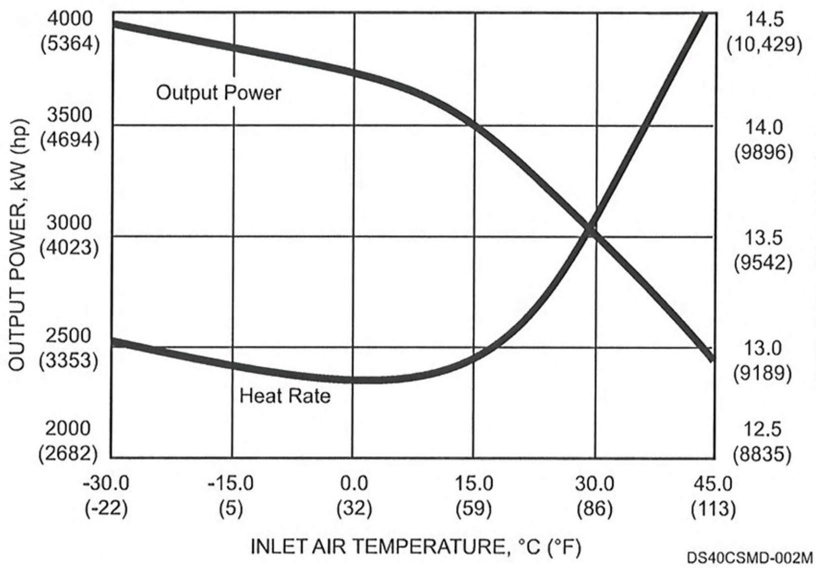
Natural gas fuel with
LHV = 35 MJ/nm³ (940 Btu/scf)

Optimum power turbine speed

AC-driven accessories

Engine efficiency: 27.9%

Available Power



DS40CSMD-002M

Package Dimensions*

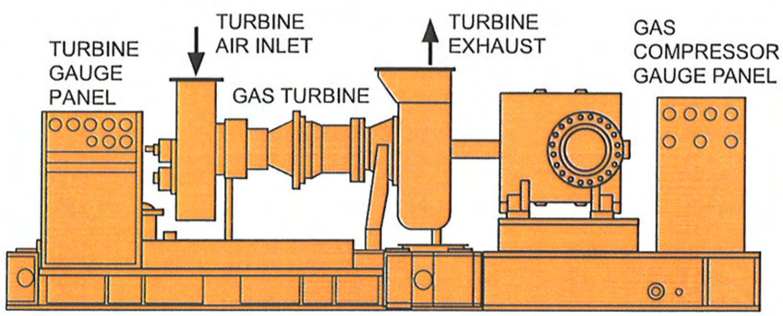
Length: 6.0 m (19' 9")

Width: 2.5 m (8' 1")

Height: 2.7 m (8' 11")

Typical Weight: 14 970 kg (33,000 lb)

** Driver package only*



DS40CS-003M

Solar Turbines Incorporated
P.O. Box 85376
San Diego, CA 92186-5376

FOR MORE INFORMATION

Telephone: (+1) 619-544-5352
Internet: www.solarturbines.com

ISO 9001
DNV
CERTIFICATED FIRM

Solar Centaur 40 Predicted Engine Performance Document

Solar Turbines
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PREDICTED ENGINE PERFORMANCE

Customer *B&V - DCP-Midstream'*	Model **CENTAUR 40-4700S**
	Package Type **CS/MD**
Job ID **Frac # II**	Match **HI-AMBIENT**
Run By **Michael E Clay** / Date Run **7-Mar-12**	Fuel System **GAS**
Engine Performance Code **REV. 3.54** / Engine Performance Data **REV. 3.1**	Fuel Type **CHOICE GAS**

DATA FOR MINIMUM PERFORMANCE

Gearbox Ratio		0.7000
Elevation	feet	50
Inlet Loss	in H2O	4.0
Exhaust Loss	in H2O	10.0
Accessory on GP Shaft	HP	14.0

		1	2	3	4	5	6
Engine Inlet Temperature	deg F	40.0	50.0	60.0	70.0	80.0	90.0
Relative Humidity	%	60.0	60.0	60.0	60.0	60.0	60.0
Gearbox Efficiency		0.9538	0.9529	0.9518	0.9508	0.9497	0.9481
Driven Equipment Speed	RPM	10847	10850	10850	10828	10803	10745
Specified Load	HP	FULL	FULL	FULL	FULL	FULL	FULL
Net Output Power	HP	4080	3996	3906	3809	3709	3552
Fuel Flow	mmBtu/hr	41.98	41.22	40.48	39.77	39.05	38.05
Heat Rate	Btu/HP-hr	10290	10313	10361	10442	10528	10712
Therm Eff	%	24.727	24.671	24.557	24.368	24.168	23.753
Engine Exhaust Flow	lbm/hr	154303	151635	148675	145348	142058	137945
PT Exit Temperature	deg F	796	809	823	837	850	864
Exhaust Temperature	deg F	796	809	823	837	850	864

Fuel Gas Composition (Volume Percent)

Methane (CH4)	95.07
Ethane (C2H6)	2.93
Propane (C3H8)	0.24
I-Butane (C4H10)	0.03
Carbon Dioxide (CO2)	1.05
Nitrogen (N2)	0.68
Sulfur Dioxide (SO2)	0.0001

Fuel Gas Properties

LHV (Btu/Scf)	918.4	Specific Gravity	0.5838	Wobbe Index at 60F	1202.0

This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

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PREDICTED ENGINE PERFORMANCE

Customer B&V - DCP-Midstream'	Model **CENTAUR 40-4700S**
	Package Type **CS/MD**
Job ID **Frac # II**	Match **HI-AMBIENT**
Run By **Michael E Clay** / Date Run **7-Mar-12**	Fuel System **GAS**
Engine Performance Code **REV. 3.54** / Engine Performance Data **REV. 3.1**	Fuel Type **CHOICE GAS**

DATA FOR MINIMUM PERFORMANCE

Gearbox Ratio		0.7000
Elevation	feet	50
Inlet Loss	in H2O	4.0
Exhaust Loss	in H2O	10.0
Accessory on GP Shaft	HP	14.0

		1	2
Engine Inlet Temperature	deg F	100.0	105.0
Relative Humidity	%	60.0	60.0
Gearbox Efficiency		0.9462	0.9454
Driven Equipment Speed	RPM	10689	10653
Specified Load	HP	FULL	FULL
Net Output Power	HP	3394	3319
Fuel Flow	mmBtu/hr	37.07	36.61
Heat Rate	Btu/HP-hr	10924	11031
Therm Eff	%	23.293	23.067
Engine Exhaust Flow	lbm/hr	134006	132047
PT Exit Temperature	deg F	876	883
Exhaust Temperature	deg F	876	883

Fuel Gas Composition (Volume Percent)

Methane (CH4)	95.07
Ethane (C2H6)	2.93
Propane (C3H8)	0.24
I-Butane (C4H10)	0.03
Carbon Dioxide (CO2)	1.05
Nitrogen (N2)	0.68
Sulfur Dioxide (SO2)	0.0001

Fuel Gas Properties

LHV (Btu/Scf)	918.4	Specific Gravity	0.5838	Wobbe Index at 60F	1202.0

This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

Solar Turbines
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PREDICTED EMISSION PERFORMANCE

Customer **B&V - DCP-Midstream'**	Engine Model **CENTAUR 40-4700S** **CS/MD HI-AMBIENT**
Job ID **Frac # II**	
Inquiry Number **TBD**	Fuel Type: **CHOICE GAS** Water Injection: **NO**
Run By: **Michael E Clay** Date Run: **7-Mar-12**	Engine Emissions Data **REV. 0.1**

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
1 — 4080 HP, 100.0% Load, Elev. 50 ft, Rel. Humidity 60.0%, Temperature 40.0 Deg. F			
PPMvd at 15% O2	25.00	50.00	25.00
ton/yr	18.37	22.37	6.41
lbm/hr	4.19	5.11	1.46
g/(Hp-hr) (gas turbine shaft pwr)	0.49	0.60	0.17
2 — 3996 HP, 100.0% Load, Elev. 50 ft, Rel. Humidity 60.0%, Temperature 50.0 Deg. F			
PPMvd at 15% O2	25.00	50.00	25.00
ton/yr	18.01	21.93	6.28
lbm/hr	4.11	5.01	1.43
g/(Hp-hr) (gas turbine shaft pwr)	0.49	0.60	0.17
3 — 3906 HP, 100.0% Load, Elev. 50 ft, Rel. Humidity 60.0%, Temperature 60.0 Deg. F			
PPMvd at 15% O2	25.00	50.00	25.00
ton/yr	17.65	21.49	6.15
lbm/hr	4.03	4.91	1.41
g/(Hp-hr) (gas turbine shaft pwr)	0.49	0.60	0.17

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
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PREDICTED EMISSION PERFORMANCE

Customer **B&V - DCP-Midstream'**	Engine Model **CENTAUR 40-4700S CS/MD HI-AMBIENT**
Job ID **Frac # II**	
Inquiry Number **TBD**	Fuel Type: **CHOICE GAS** — Water Injection: **NO**
Run By: **Michael E Clay** — Date Run: **7-Mar-12**	Engine Emissions Data **REV. 0.1**

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
4 — 3809 HP, 100.0% Load, Elev. 50 ft, Rel. Humidity 60.0%, Temperature 70.0 Deg. F			
PPMvd at 15% O2	25.00	50.00	25.00
ton/yr	17.29	21.06	6.03
lbm/hr	3.95	4.81	1.38
g/(Hp-hr) (gas turbine shaft pwr)	0.49	0.60	0.17
5 — 3709 HP, 100.0% Load, Elev. 50 ft, Rel. Humidity 60.0%, Temperature 80.0 Deg. F			
PPMvd at 15% O2	25.00	50.00	25.00
ton/yr	16.92	20.60	5.90
lbm/hr	3.86	4.70	1.35
g/(Hp-hr) (gas turbine shaft pwr)	0.50	0.61	0.17
6 — 3552 HP, 100.0% Load, Elev. 50 ft, Rel. Humidity 60.0%, Temperature 90.0 Deg. F			
PPMvd at 15% O2	25.00	50.00	25.00
ton/yr	16.40	19.97	5.72
lbm/hr	3.74	4.56	1.31
g/(Hp-hr) (gas turbine shaft pwr)	0.50	0.61	0.18

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer		Engine Model	
B&V - DCP-Midstream'		**CENTAUR 40-4700S CS/MD HI-AMBIENT**	
Job ID: **Frac # II**			
Inquiry Number: **TBD**		Fuel Type: **CHOICE GAS**	Water Injection: **NO**
Run By: **Michael E Clay**	Date Run: **7-Mar-12**	Engine Emissions Data: **REV. 0.1**	

1	3394 HP 100.0% Load	Elev. 50 ft	Rel. Humidity 60.0%	Temperature 100.0 Deg. F
		NOx EMISSIONS	**CO EMISSIONS**	**UHC EMISSIONS**
PPMvd at 15% O2		25.00	50.00	25.00
ton/yr		15.87	19.33	5.54
lbm/hr		3.62	4.41	1.26
g/(Hp-hr) (gas turbine shaft pwr)		0.51	0.62	0.18

2	3319 HP 100.0% Load	Elev. 50 ft	Rel. Humidity 60.0%	Temperature 105.0 Deg. F
		NOx EMISSIONS	**CO EMISSIONS**	**UHC EMISSIONS**
PPMvd at 15% O2		25.00	50.00	25.00
ton/yr		15.62	19.01	5.45
lbm/hr		3.57	4.34	1.24
g/(Hp-hr) (gas turbine shaft pwr)		0.52	0.63	0.18

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

ATTACHMENT D

SUPPORTING BACT INFORMATION

CCS Cost Estimation Study

CO_2 Pipeline Cost Estimation Guidance

Entergy Fuel Mix Data

Alternative Turbine Specification Sheet

Denbury Green Pipeline Map

Good Combustion Practices

TCEQ Fugitive Guidance

CCS Cost Estimation Study

Table D-1
CCS Equipment Capital Cost Estimate[1]
CCS Cost Estimation Study
DCP Midstream - Hardin County NGL Fractionation Plant

DIRECT COSTS, (DC)			
CO_2 Capture Efficiency			90%
Skid Equipment Cost 2012$			$111,798,000
Total Equipment Cost (A) - 2012$			$111,798,000
Instrumentation (10% x A)			$11,179,800
Sales tax (8.25% x A)			$9,223,300
Freight (5% x A)			$5,589,900
Purchased Equipment Cost, (B)			**$137,791,000**
Direct Installation Costs			
Foundation & Supports	0.08 x B		$11,023,300
Erection & Handling	0.14 x B		$19,290,700
Electrical	0.04 x B		$5,511,600
Piping	0.02 x B		$2,755,800
Insulation	0.01 x B		$1,377,900
Painting	0.01 x B		$1,377,900
Subtotal			**$41,337,200**
Site Preparation		As Required	
Building		As Required	
Total Direct Costs			**$179,128,200**
INDIRECT COSTS, (IC)			
Engineering	0.10 x B		$13,779,100
Construction and Field Expenses	0.05 x B		$6,889,600
Contractor Fee	0.10 x B		$13,779,100
Start-up	0.02 x B		$2,755,800
Performance Test	0.01 x B		$1,377,900
Contingencies	0.03 x B		$4,133,700
Other (ER, SPCC, RMP Plans)	other		$20,000
Total Indirect Costs			**$42,735,200**
TOTAL CAPITAL COSTS, (CC)			**$221,863,400**

[1] Reference: EPA Air Pollution Control Cost Manual, Sixth Edition - EPA/452/B-02-001, Section 4.2, Chapter 2

Table D-2

Operating Cost Estimate[1]

CCS Cost Estimation Study

DCP Midstream - SET Frac Plant

TOTAL CAPITAL COST		
CO_2 CCS Unit		$221,863,400
DIRECT OPERATING COST, $/yr		
Operating Labor		
Operators Labor, 8 hrs/shift, 3 shifts/day @ $32.50/hr		$284,700
Supervision, 15% of Operator		$42,700
Maintenance		
Analyzer Technician (0.5 hrs/day, 365 days/yr @ $33.47/hr)		$6,100
Utilities & Operating Expenses		
Electricity: (12 MWh)(8760 hrs)($0.07/kwh)		$7,358,400
Amine: (1.0 gal/hr)($1.00/gal)		$8,760
Total Direct Operating Cost, $/yr		**$7,700,660**
INDIRECT OPERATING COSTS, $/yr		
Overhead		
60% of operators, supervisors and maintenance labor and material		$200,100
Administrative charges	0.02 x CC	$4,437,300
Property Taxes	0.01 x CC	$2,218,600
Insurance	0.01 x CC	$2,218,600
Capital Recovery Cost, 10 years, 10% = 0.1628		$36,119,400
Total Indirect Operating Cost, $/yr		**$45,194,000**
TOTAL ANNUAL OPERATING COST		**$52,894,660**
CO_2 Emission Reduction (183,950.44 tpy @ 90%)		615,717.90
TOTAL ANNUALIZED COST, $/TON CO_2 REMOVED*		**$86**
*Excluding:		
Process Royalty Fees		
Permit Fees & Special Engineering for Permits		
Fuel Costs		

[1] Reference: EPA Air Pollution Control Cost Manual, Sixth Edition - EPA/452/B-02-001, Section 4.2, Chapter 2

Table D-3

CO_2 Pipeline Capital Cost Estimate[1]

CCS Cost Estimation Study

DCP Midstream - Hardin County NGL Fractionation Plant

Pipeline diameter (in)	6
Pipeline Length (miles)	28

Pipeline Costs			
Cost Type	**Units**	**Formula**	**Cost**
Materials	$ Diameter (in) Length (mi)	$64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D + 26,960)	$ 2,290,902.76
Labor	$ Diameter (in) Length (mi)	$341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)	$ 10,432,898.96
Miscellaneous	$ Diameter (in) Length (mi)	$150,166+ $1.58 x L x (8,417 x D + 7,234)	$ 2,704,406.64
Right of Way	$ Diameter (in) Length (mi)	$48,037+ $1.20 x L x (577 x D + 29,788)	$ 1,165,237.00
Other Capital			
Cost Type	**Units**	**Formula**	**Cost**
CO_2 Surge Tank	$	Fixed	$ 1,150,636.00
Pipeline Control System	$	Fixed	$ 110,632.00
O&M			
Cost Type	**Units**	**Formula**	**Cost**
Fixed O&M	$/mile/year	Fixed	$ 8,632.00

Total Capital Cost	$	$ 17,854,713.36
Depreciation (Amortized over 10 Years at 10%)		$ 2,905,854.60

Annual O&M	$ 241,696.00
Depreciation	$ 2,905,854.60
Annual Pipeline Costs	**$ 3,147,550.60**
Annual CCS Equipment Costs	**$ 52,894,660.00**
Total CCS Costs	**$ 56,042,210.60**

Total Tons CO_2	684,131.00
Estimated Reduction	90%
Total CO_2 Sequestered	615,717.90

Cost Per Ton Reduction	**$ 91.02**

[1] Estimated using the National Energy Technology Laboratory's document "Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs." (DOE/NETL-2010/1447, March 2010)

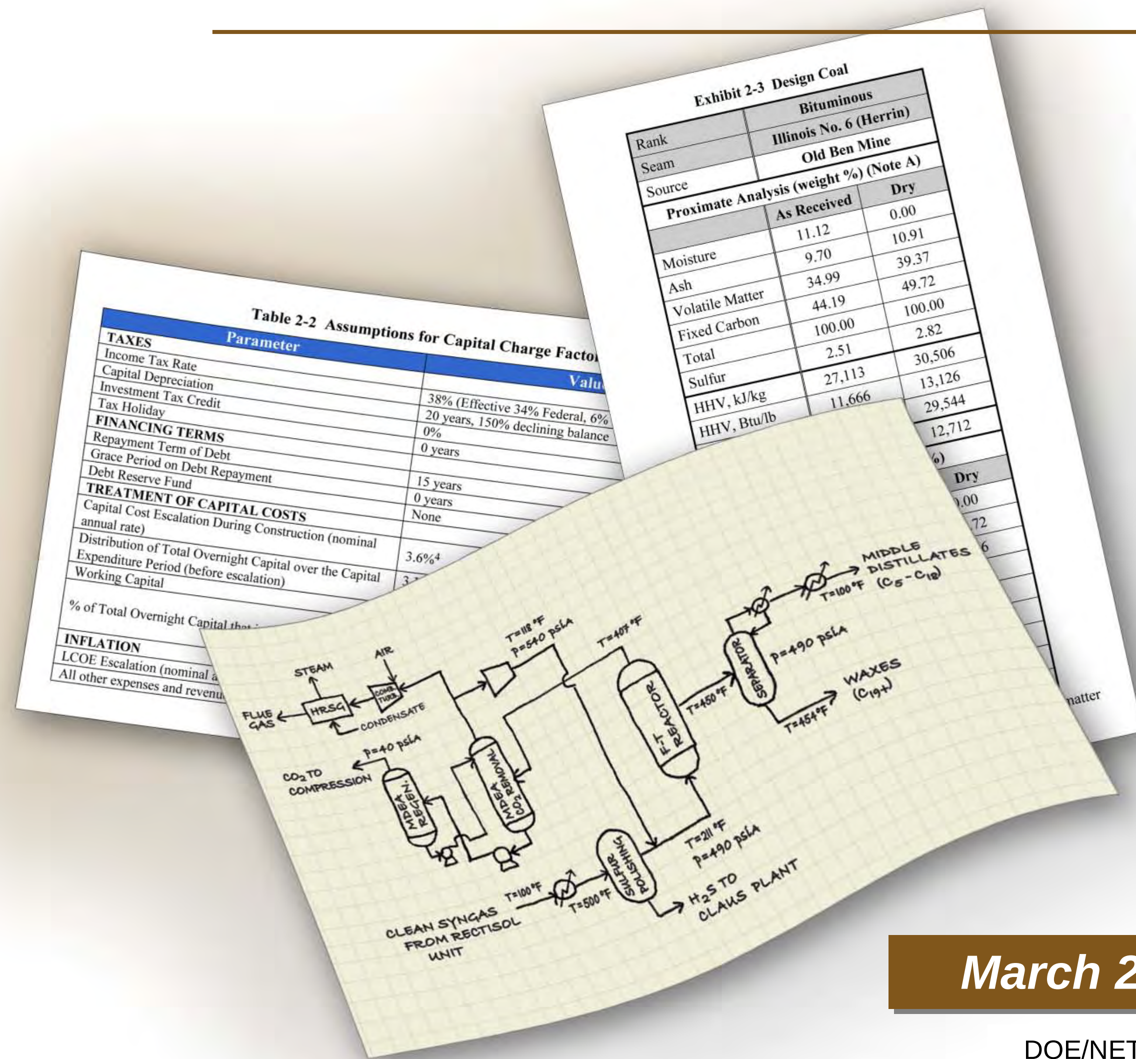
CO_2 Pipeline Cost Estimation Guidance

the ENERGY lab

NETL

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

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]	$\$94,029 \times \left(\frac{7,389}{280 \times \#\,of\ injection\ wells}\right)^{0.5}$
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*	$\$23,478 \times \left(\frac{7,389}{280 \times \#\,of\ injection\ wells}\right)^{0.5}$
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 30^{th} (and final) year of injection. The plume grows by 1% per year thereafter, to a size of 510 km^2 after the 80^{th} 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

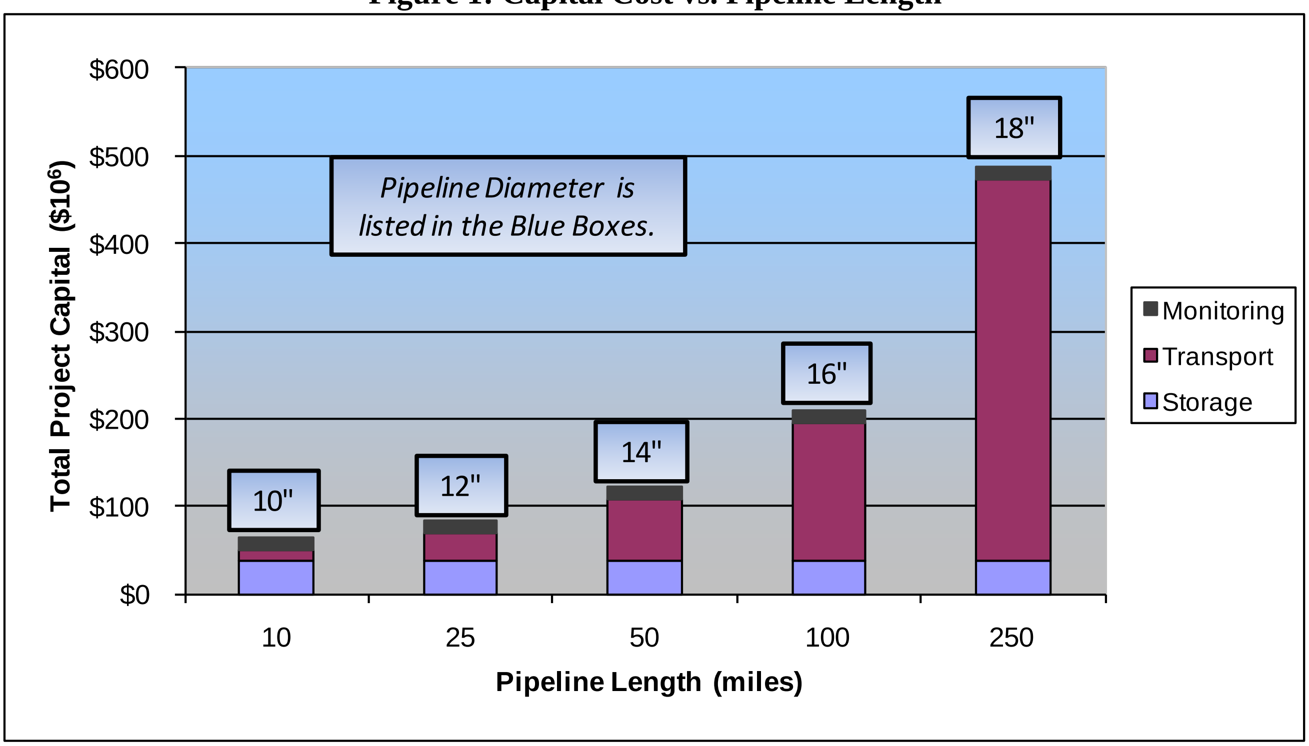
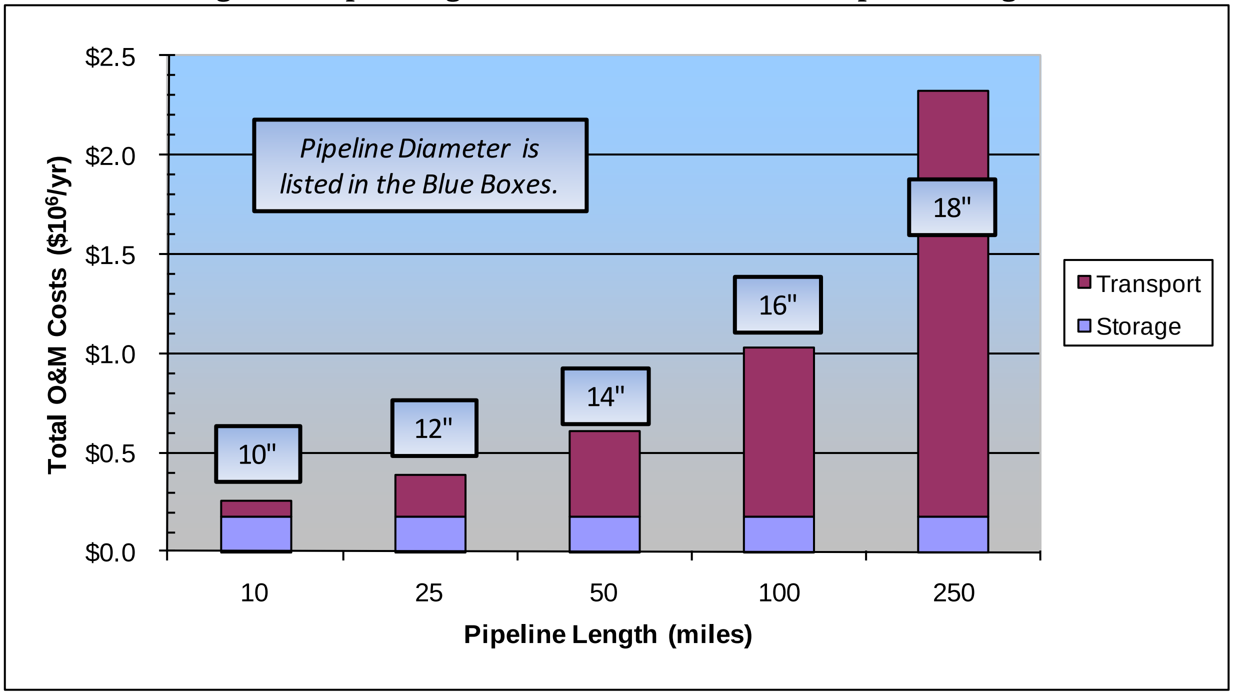


Figure 2: Operating and Maintenance Cost vs. Pipeline Length



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

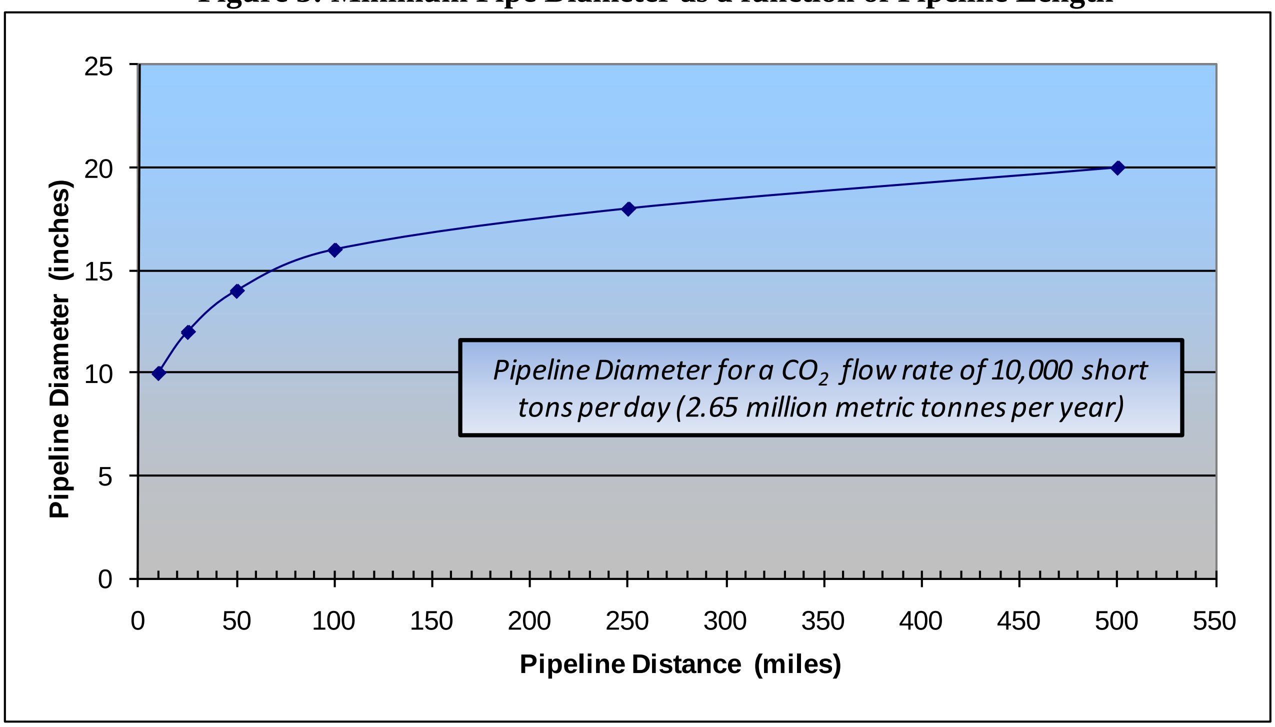
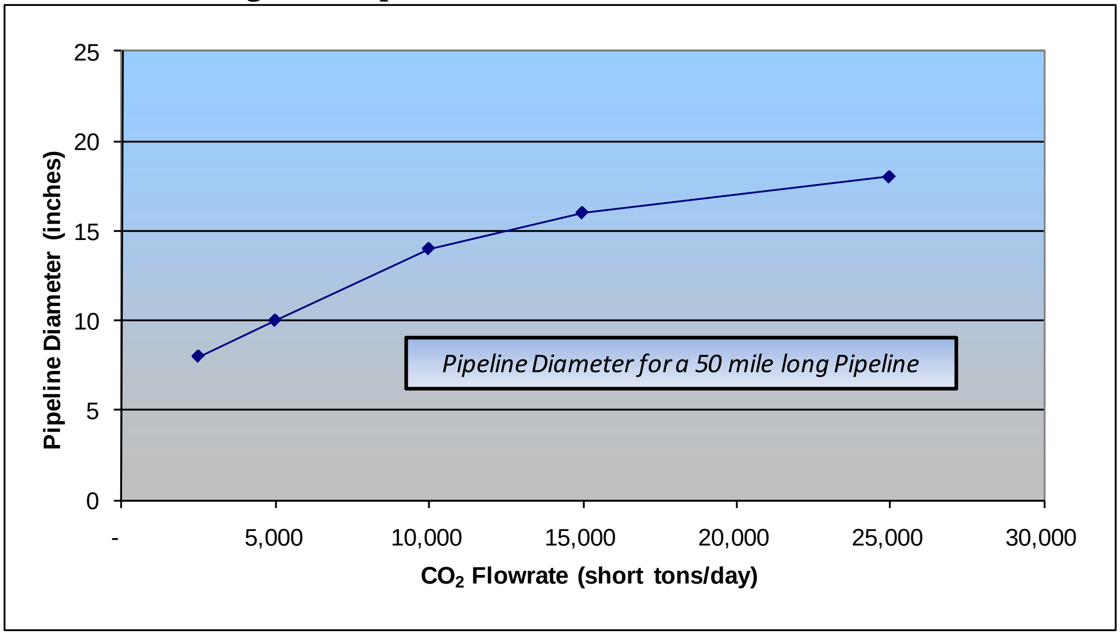


Figure 4: Pipe Diameter as a Function of CO_2 Flow Rate



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

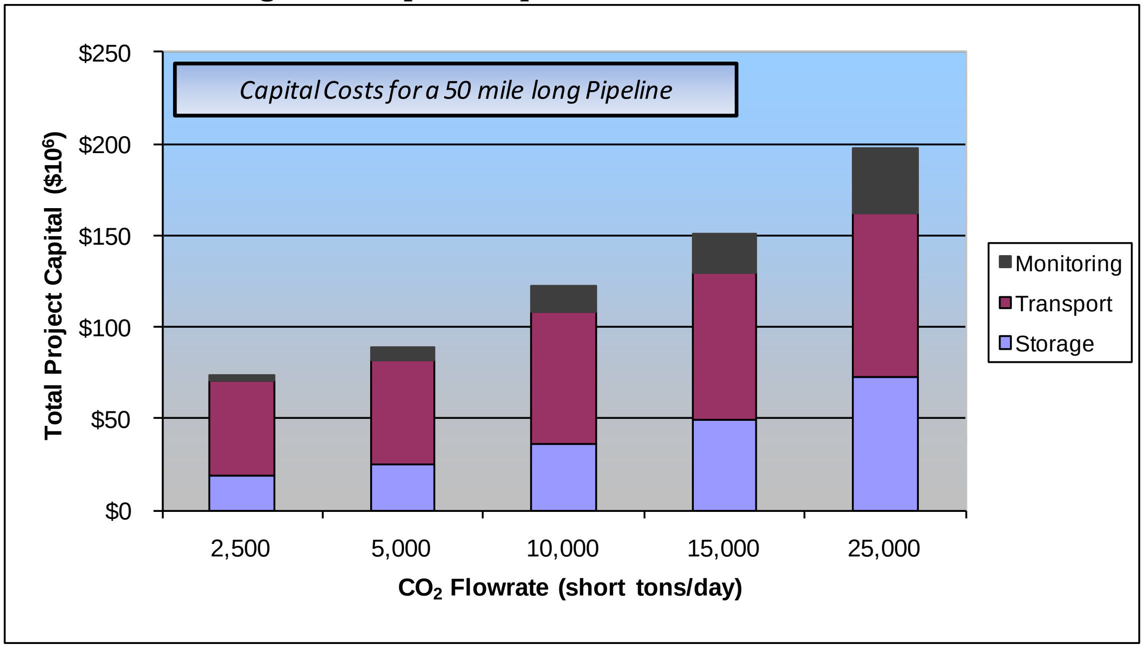
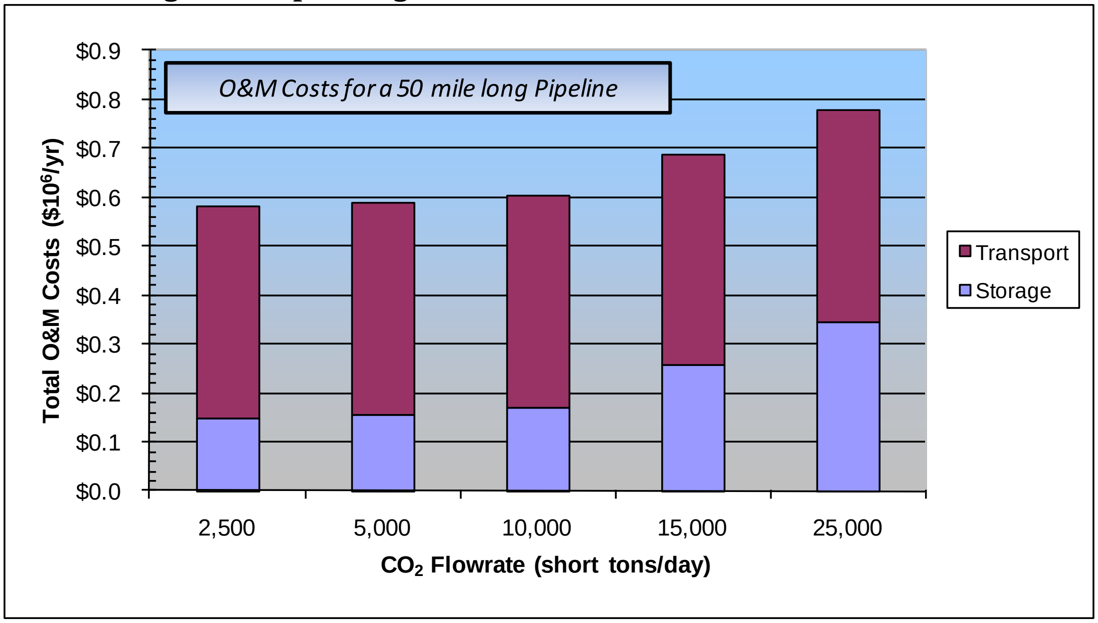
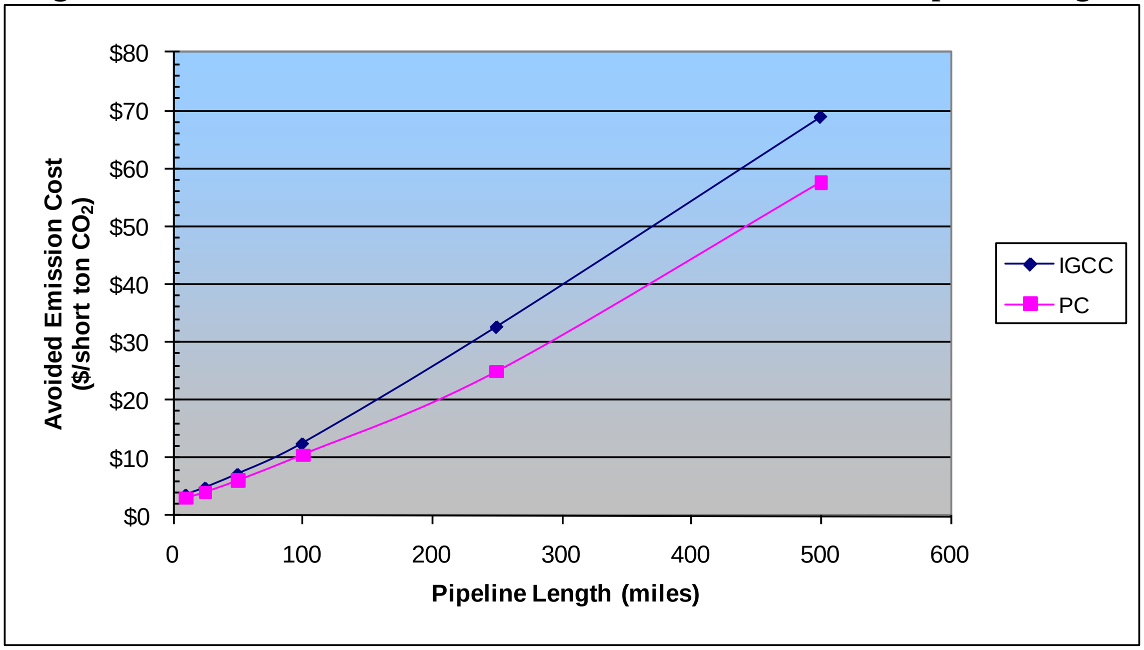


Figure 6: Operating and Maintenance Cost vs. CO_2 Flow Rate



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.

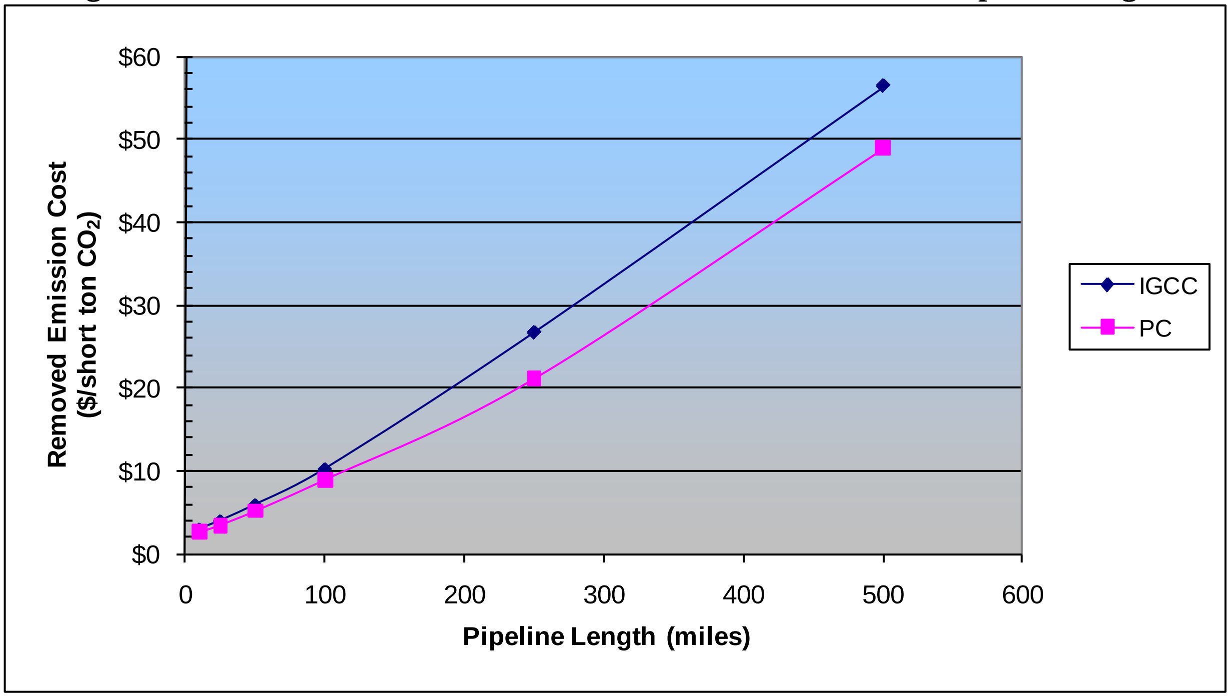
Figure 7: Avoided Emission Costs for 550 MW Power Plants vs. Pipeline Length



[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.

Figure 8: Removed Emission Costs for 550 MW Power Plants vs. Pipeline Length



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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Entergy Fuel Mix Data

Control Number: 37856

Item Number: 3

Addendum StartPage: 0

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF JANUARY 2010

Current System Fuel Factor: (1)

	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:				
Gains from Disposition of Allowances	411	$ -	$ -	$ -
Fuel Cost	501	$ 35,333,749	$ 161,417	$ 35,495,166
Allowances	509	$ 9,889	$ -	$ 9,889
Nuclear Fuel Cost	518	-	-	-
Purchased Power Cost - Nuclear	555	1,665,487	9,120,144	10,785,631
Purchased Power Cost - Non-Nuclear	555	57,855,664	8,722,480	66,578,144
TOTAL SYSTEM COST:		$ 94,864,789	$ 18,004,041	$ 112,868,830
(2) Sales for Resale Revenue	447	23,952,620	5,150,383	29,103,003
NET SYSTEM COST:		$ 70,912,169	$ 12,853,658	$ 83,765,827
Texas Fixed Fuel Factor Allocator		96.324%	96.324%	96.324%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 68,305,438	$ 12,381,158	$ 80,686,596

	ACCOUNT	REVENUES	MWH SALES
TEXAS FIXED FUEL FACTOR RELATED REVENUES:			
Residential	440	$ 27,905,265	584,183
Commercial & Industrial	442	34,439,513	747,697
Street & Highway	444	308,976	6,468
Public Authorities	445	967,855	20,543
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 63,621,609	1,358,891

	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
OVER/(UNDER) RECOVERY OF COSTS:				
Annual Interest Compound Rate (%):			0.61%	
Beginning Cumulative Balance	182	110,580,346	(7,626,320)	102,954,026
Entry This Month	182	(4,683,829)	52,189	(4,631,640)
Docket No. 37580 Refund	182	(50,613,301)	(621,431)	(51,234,732)
Adjustment	182	-	-	-
Ending Cumulative Balance	182	$ 55,283,216	$ (8,195,562)	$ 47,087,654

Comments:
(1) The Texas retail fixed fuel factor is 4.61704 cents/kWh effective with September 2009 billing cycles.
(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF JANUARY 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,482,511	$ 3,020,221	$ 2.037	87,186	$ 34.641	8,502.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	8	119	14.875	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	2,453,473	4,525,965	1.845	142,681	31.721	8,597.8
SunCoast Products	Igniter Fuel	Firm		Nelson 6	12,286	194,571	15.837	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	27,339	147,522	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	(875)	(14,010)	-	-	-	-
				TOTAL COAL:	3,974,742	$ 7,874,388	$ 1.981	229,867	$ 34.256	8,645.7
DCP MIDSTREAM	NG	SPOT		Sabine	375,000	$ 2,230,125	$ 5.947			
ENBRIDGE	NG	SPOT		Sabine	2,785,000	16,236,025	5.830			
JP MORGAN VNTRS	NG	SPOT		Sabine	175,000	1,213,250	6.933			
KINDER	NG	SPOT		Sabine	350,000	2,262,125	6.463			
ONEOK EM&T	NG	SPOT		Sabine	220,000	1,392,300	6.329			
SEQUENT	NG	SPOT		Sabine	160,000	1,066,500	6.666			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	3,744	(771,975)	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	4,068,744	$ 23,628,350	$ 5.807			
ENBRIDGE	NG	SPOT		Lewis Creek	450,000	$ 2,692,145	$ 5.983			
JP MORGAN VNTRS	NG	SPOT		Lewis Creek	55,000	340,650	6.194			
PACIFIC SUMMIT	NG	SPOT		Lewis Creek	250,000	1,470,025	5.880			
SEQUENT	NG	SPOT		Lewis Creek	365,000	2,249,135	6.162			
SW ENERGY	NG	SPOT		Lewis Creek	215,000	1,327,375	6.174			
TAUBER	NG	SPOT		Lewis Creek	310,000	1,804,665	5.822			
TETCO	NG	SPOT		Lewis Creek	-	109,500	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek			-			
Prior Period Adjustments	NG	N/A		Lewis Creek	(133,735)	(83,740)	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	1,511,265	$ 9,909,755	$ 6.557			

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF JANUARY 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
	NG	SPOT		Nelson			$ -			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	Oil	SPOT		Nelson			-			
Prior Period Adjustments	NG	N/A		Nelson	-	-	-			
Prior Period Adjustments	Oil	N/A		Nelson	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	NG	SPOT		Willow Glen			$ -			
	Oil	SPOT		Willow Glen	-	-	-			
Prior Period Adjustments	NG	N/A		Willow Glen	-	-	-			
Prior Period Adjustments	Oil	N/A		Willow Glen	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	Oil	SPOT		La. Station	-	-	-			
Prior Period Adjustments	NG	N/A		La. Station	-	-	-			
Prior Period Adjustments	Oil	N/A		La. Station	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
		TOTAL NATURAL GAS & OIL			5,580,009	$ 33,538,105	$ 6.010			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF JANUARY 2010

Time Period: 744 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
NUCLEAR:	River Bend 1	697.0	-	-	$ -	0.00%	-	$ -	$ -	0.00%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL NUCLEAR	697.0	-	-	$ -	0.00%	-	$ -	$ -	0.00%
COAL/OIL:	Nelson 6	385.0	119,137	1,260,072	$ 3,037,146	41.59%	10.577	$ 2.410	$ 25.49	7.71%
	Big Cajun No. 2 Unit 3	227.0	65,587	658,525	1,201,873	38.83%	10.040	1.825	18.32	4.24%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	184,724	1,918,598	$ 4,239,019	40.57%	10 386	$ 2.209	$ 22.95	11.95%
GAS/OIL:	Lewis Creek	520 0	142,271	1,645,000	$ 9,993,495	36.77%	11.562	$ 6.075	$ 70.24	9.20%
	Nelson	646.0	-	-	-	0.00%	-	-	-	0.00%
	Sabine	1,890.0	309,819	3,614,329	21,910,472	22.03%	11.666	6.062	70.72	20.04%
	Willow Glen	2,045.0	-	-	-	0.00%	-	-	-	0.00%
	Louisiana Station	140.0	-	-	-	0.00%	-	-	-	0.00%
	Prior Period Adjustments		-	(118,387)	(809,237)	-	-	-	-	0.00%
	TOTAL GAS/OIL	5,241.0	452,090	5,140,942	$ 31,094,730	11.59%	11.372	$ 6.048	$ 68.78	29.25%
EMISSIONS:	Lewis Creek	-	-	-	9,889	-	-	-	-	0.00%
	Nelson	-	-	-	-	-	-	-	-	0.00%
	Sabine	-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 9,889	-	-	$ -	$ -	
	TOTAL NET GENERATION	6,550.0	636,814	7,059,540	$ 35,343,638	13.07%	11.086	$ 5.007	$ 55.50	41.20%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		404,533	N/A	21,097,005	N/A	N/A	N/A	52.15	26.17%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		404,533		$ 21,097,005				$ 52.15	26.17%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		504,338	N/A	14,471,526	N/A	N/A	N/A	28.69	32.63%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		504,338		$ 14,471,526				$ 28.69	32.63%
	TOTAL PURCHASES		908,871		$ 35,568,531				$ 39.13	58.80%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,545,685		$ 70,912,169				$ 45.88	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,383,337							89.50%
	Sales for Resale		35,864		$ 52,594,822					2.32%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,868							0.12%
	TOTAL @ THE METER		1,421,069							91.94%
	Total Energy Losses *		124,616							8.06%
	Percent Losses *									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	(92)	(928)	$ (18,794)	N/A	-	$ 20.243	$ 204.28	-0.01%
	Nelson 6	385.0	44	468	6,846	N/A	10.632	14.634	155.59	0.00%
	Nelson G & O	646.0	-	-	-	N/A	-	-	-	0.00%
	Sabine	1,890.0	3	34	504	N/A	11.333	14.824	168.00	0.00%
	Willow Glen	2,034.0	-	-	-	N/A	-	-	-	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		(45)	(427)	$ (11,444)		9.480	$ 26.827	$ 254.31	0.00%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

(2) Other Non-Firm Purchases are net of off-system sales: 347,832 mWh
$ 23,952,620

Control Number: 37856

Item Number: 20

Addendum StartPage: 0

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF FEBRUARY 2010

Current System Fuel Factor: (1)

	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:				
Gains from Disposition of Allowances	411	$ -	$ -	$ -
Fuel Cost	501	$ 24,757,961	$ 77,712	$ 24,835,673
Allowances	509	$ 7,759	$ -	$ 7,759
Nuclear Fuel Cost	518	-	-	-
Purchased Power Cost - Nuclear	555	1,539,098	10,150,171	11,689,269
Purchased Power Cost - Non-Nuclear	555	46,959,655	8,566,860	55,526,515
TOTAL SYSTEM COST:		$ 73,264,473	$ 18,794,743	$ 92,059,216
(2) Sales for Resale Revenue	447	12,313,516	3,936,815	16,250,331
NET SYSTEM COST:		$ 60,950,957	$ 14,857,928	$ 75,808,885
Texas Fixed Fuel Factor Allocator		87.219%	87.219%	87.219%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 53,160,815	$ 12,958,936	$ 66,119,751

	ACCOUNT	REVENUES	MWH SALES
TEXAS FIXED FUEL FACTOR RELATED REVENUES:			
Residential	440	$ 22,760,722	476,485
Commercial & Industrial	442	33,690,681	732,915
Street & Highway	444	320,033	6,700
Public Authorities	445	821,099	17,409
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 57,592,535	1,233,509

	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
OVER/(UNDER) RECOVERY OF COSTS:				
Annual Interest Compound Rate (%):			0.61%	
Beginning Cumulative Balance	182	55,283,216	(8,195,562)	47,087,654
Entry This Month	182	4,431,720	23,870	4,455,590
Docket No. ER08-1056, 2008 RPCE Overpayment	182	(970,925)	-	(970,925)
Docket No. 37580 Refund	182	(24,412,657)	(299,739)	(24,712,396)
Ending Cumulative Balance	182	$ 34,331,354	$ (8,471,431)	$ 25,859,923

Comments:

(1) The Texas retail fixed fuel factor is 4.61704 cents/kWh effective with September 2009 billing cycles.

(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF FEBRUARY 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,489,989	$ 2,958,920	$ 1.986	87,729	$ 33.728	8,492.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	825	13,078	15.852	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	2,136,460	5,313,933	2.487	122,997	43.204	8,685.0
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	27,339	149,521	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	817	12,959	-	-	-	-
				TOTAL COAL:	3,655,430	$ 8,448,411	$ 2.311	210,726	$ 40.092	8,673.4
ENBRIDGE	NG	SPOT		Sabine	2,590,000	$ 14,357,843	$ 5.544			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	3,983	370,024	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	2,593,983	$ 14,727,867	$ 5.678			
ENBRIDGE	NG	SPOT		Lewis Creek	345,000	$ 1,960,275	$ 5.682			
PACIFIC SUMMIT	NG	SPOT		Lewis Creek	110,000	605,115	5.501			
SEQUENT	NG	SPOT		Lewis Creek	280,000	1,470,420	5.252			
SW ENERGY	NG	SPOT		Lewis Creek	40,000	200,800	5.020			
TAUBER	NG	SPOT		Lewis Creek	220,000	1,187,380	5.397			
TETCO	NG	SPOT		Lewis Creek	-	109,500	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek			-			
Prior Period Adjustments	NG	N/A		Lewis Creek	(16,526)	(77,601)	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	978,474	$ 5,455,889	$ 5.576			

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF FEBRUARY 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
	NG	SPOT		Nelson			$ -			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	Oil	SPOT		Nelson			-			
Prior Period Adjustments	NG	N/A		Nelson	-	-	-			
Prior Period Adjustments	Oil	N/A		Nelson	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	NG	SPOT		Willow Glen			$ -			
	Oil	SPOT		Willow Glen	-	-	-			
Prior Period Adjustments	NG	N/A		Willow Glen	-	-	-			
Prior Period Adjustments	Oil	N/A		Willow Glen	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	Oil	SPOT		La. Station	-	-	-			
Prior Period Adjustments	NG	N/A		La. Station	-	-	-			
Prior Period Adjustments	Oil	N/A		La. Station	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
				TOTAL NATURAL GAS & OIL	3,572,457	$ 20,183,756	$ 5.650			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF FEBRUARY 2010

Time Period: 672 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
NUCLEAR:	River Bend 1	697.0	-	-	$ -	0.00%	-	$ -	$ -	0.00%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL NUCLEAR	697.0	-	-	$ -	0.00%	-	$ -	$ -	0.00%
COAL/OIL:	Nelson 6	385.0	107,744	1,158,466	$ 2,849,060	41.65%	10.752	$ 2.459	$ 26.44	7.60%
	Big Cajun No. 2 Unit 3	227.0	67,092	677,189	1,209,884	43.98%	10.093	1.787	18.03	4.73%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	174,836	1,835,655	$ 4,058,944	42.51%	10.499	$ 2.211	$ 23.22	12.34%
GAS/OIL:	Lewis Creek	520.0	85,535	995,000	$ 5,533,490	24.48%	11.633	$ 5.561	$ 64.69	6.04%
	Nelson	646.0	-	-	-	0.00%	-	-	-	0.00%
	Sabine	1,890.0	226,936	2,656,778	14,629,241	17.87%	11.707	5.506	64 46	16.01%
	Willow Glen	2,045.0	-	-	-	0.00%	-	-	-	0.00%
	Louisiana Station	140.0	-	-	-	0.00%	-	-	-	0.00%
	Prior Period Adjustments		-	36,294	536,286	-	-	-	-	0.00%
	TOTAL GAS/OIL	5,241.0	312,471	3,688,072	$ 20,699,017	8.87%	11.803	$ 5.612	$ 66.24	22.05%
EMISSIONS:	Lewis Creek	-	-	-	7,759	-	-	-	-	0.00%
	Nelson	-	-	-	-	-	-	-	-	0.00%
	Sabine	-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 7,759	-	-	$ -	$ -	
	TOTAL NET GENERATION	6,550.0	487,307	5,523,727	$ 24,765,720	11.07%	11.335	$ 4.484	$ 50.82	34.38%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		417,425	N/A	20,076,139	N/A	N/A	N/A	48.10	29.45%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		417,425		$ 20,076,139				$ 48.10	29.45%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		512,607	N/A	16,109,099	N/A	N/A	N/A	31.43	36.17%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		512,607		$ 16,109,099				$ 31.43	36.17%
	TOTAL PURCHASES		930,032		$ 36,185,238				$ 38.91	65.62%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,417,339		$ 60,950,958				$ 43.00	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,287,297							90.82%
	Sales for Resale		135,438		$ 32,055,692					9.56%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,579							0.11%
	TOTAL @ THE METER		1,424,314							100.49%
	Total Energy Losses *		(6,975)							-0.49%
	Percent Losses *									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	184	1,859	$ 36,028	N/A	10.105	$ 19.378	$ 195.80	0.01%
	Nelson 6	385.0	45	484	8,468	N/A	10.758	17.492	188.18	0.00%
	Nelson G & O	646.0	-	-	-	N/A	-	-	-	0.00%
	Sabine	1,890.0	1	11	154	N/A	11.000	14.000	154.00	0.00%
	Willow Glen	2,034 0	-	-	-	N/A	-	-	-	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		230	2,354	$ 44,650		10.236	$ 18.965	$ 194 13	0.02%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

(2) Other Non-Firm Purchases are net of off-system sales: 255,922 mWh
$ 12,313,516

Control Number: 37856

Item Number: 35

Addendum StartPage: 0

PROJECT NO. 37856 RECEIVED

ENTERGY TEXAS, INC. 10 MAY 20 AM 9:31
FUEL COST REPORT
FOR THE MONTH OF MARCH 2010 PUBLIC UTILITY COMMISSION
FILING CLERK

Current System Fuel Factor. (1)

	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:				
Gains from Disposition of Allowances	411	$ -	$ -	$ -
Fuel Cost	501	$ 21,480,800	$ 122,396	$ 21,603,196
Allowances	509	$ 6,215	$ -	$ 6,215
Nuclear Fuel Cost	518	-	-	-
Purchased Power Cost - Nuclear	555	1,613,192	8,431,423	10,044,615
Purchased Power Cost - Non-Nuclear	555	30,429,693	7,639,667	38,069,360
TOTAL SYSTEM COST:		$ 53,529,900	$ 16,193,486	$ 69,723,386
(2) Sales for Resale Revenue	447	11,801,845	6,001,300	17,803,145
NET SYSTEM COST:		$ 41,728,055	$ 10,192,186	$ 51,920,241
Texas Fixed Fuel Factor Allocator		89.356%	89.356%	89.356%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 37,286,521	$ 9,107,330	$ 46,393,851

	ACCOUNT	REVENUES	MWH SALES
TEXAS FIXED FUEL FACTOR RELATED REVENUES:			
Residential	440	$ 23,839,573	435,732
Commercial & Industrial	442	36,754,759	697,444
Street & Highway	444	389,254	7,115
Public Authorities	445	902,661	16,692
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 61,886,247	1,156,983

	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
OVER/(UNDER) RECOVERY OF COSTS:				
Annual Interest Compound Rate (%):			0.61%	
Beginning Cumulative Balance	182	34,331,354	(8,471,431)	25,859,923
Entry This Month	182	24,599,726	13,109	24,612,835
For Future Use	182	-	-	-
Docket No. 37580 Refund	182	(22,955,297)	(281,846)	(23,237,143)
Ending Cumulative Balance	182	$ 35,975,783	$ (8,740,168)	$ 27,235,615

Comments:
(1) The Texas retail fixed fuel factor is 5.28816 cents/kWh effective with March 2010 billing cycles.
(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF MARCH 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,412,150	$ 2,846,552	$ 2.016	83,097	$ 34.256	8,497.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	204	2,345	11.495	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	1,755,427	4,401,433	2.507	102,282	43.032	8,581.3
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	27,339	168,754	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	(621)	(10,733)	-	-	-	-
				TOTAL COAL:	3,194,499	$ 7,408,351	$ 2.319	185,379	$ 39.963	8,616.1
ENBRIDGE	NG	SPOT		Sabine	1,940,000	$ 9,778,413	$ 5.040			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	6,347	436,584	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	1,946,347	$ 10,214,997	$ 5.248			
CONOCO	NG	SPOT		Lewis Creek	10,000	$ 49,269	$ 4.927			
ENBRIDGE	NG	SPOT		Lewis Creek	630,000	3,010,980	4.779			
PACIFIC SUMMIT	NG	SPOT		Lewis Creek	120,000	528,938	4.408			
SEQUENT	NG	SPOT		Lewis Creek	310,000	1,406,850	4.538			
SW ENERGY	NG	SPOT		Lewis Creek	25,000	117,575	4.703			
TAUBER	NG	SPOT		Lewis Creek	425,000	1,872,638	4.406			
TETCO	NG	SPOT		Lewis Creek	-	109,500	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek			-			
Prior Period Adjustments	NG	N/A		Lewis Creek	35,933	230,429	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	1,555,933	$ 7,326,179	$ 4.709			

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF MARCH 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
	NG	SPOT		Nelson			$ -			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	Oil	SPOT		Nelson			-			
Prior Period Adjustments	NG	N/A		Nelson	-	-	-			
Prior Period Adjustments	Oil	N/A		Nelson	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	NG	SPOT		Willow Glen			$ -			
	Oil	SPOT		Willow Glen	-	-	-			
Prior Period Adjustments	NG	N/A		Willow Glen	-	-	-			
Prior Period Adjustments	Oil	N/A		Willow Glen	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	Oil	SPOT		La Station	-	-	-			
Prior Period Adjustments	NG	N/A		La. Station	-	-	-			
Prior Period Adjustments	Oil	N/A		La. Station	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
		TOTAL NATURAL GAS & OIL			3,502,280	$ 17,541,175	$ 5.009			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF MARCH 2010

Time Period: 744 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
NUCLEAR:	River Bend 1	697.0	-	-	$ -	0.00%	-	$ -	$ -	0 00%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL NUCLEAR	697.0	-	-	$ -	0 00%	-	$ -	$ -	0.00%
COAL/OIL:	Nelson 6	385.0	72,459	771,263	$ 1,883,658	25 30%	10.644	$ 2.442	$ 26.00	5.84%
	Big Cajun No. 2 Unit 3	227 0	76,869	763,783	1,383,915	45 51%	9.936	1 812	18.00	6.20%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	149,328	1,535,046	$ 3,267,573	32 80%	10.280	$ 2.129	$ 21.88	12.04%
GAS/OIL:	Lewis Creek	520.0	132,830	1,520,000	$ 7,095,750	34.33%	11.443	$ 4.668	$ 53 42	10.71%
	Nelson	646.0	-	-	-	0.00%	-	-	-	0.00%
	Sabine	1,890 0	161,794	2,088,230	10,380,782	11.51%	12.907	4.971	64 16	13.04%
	Willow Glen	2,045.0	-	-	-	0.00%	-	-	-	0.00%
	Louisiana Station	140.0	-	-	-	0.00%	-	-	-	0.00%
	Prior Period Adjustments		-	59,431	736,694	-	-	-	-	0.00%
	TOTAL GAS/OIL	5,241.0	294,624	3,667,661	$ 18,213,226	7.56%	12.449	$ 4.966	$ 61.82	23.75%
EMISSIONS:	Lewis Creek	-	-	-	6,215	-	-	-	-	0.00%
	Nelson	-	-	-	-	-	-	-	-	0.00%
	Sabine	-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 6,215	-	-	$ -	$ -	
	TOTAL NET GENERATION	6,550.0	443,952	5,202,707	$ 21,487,014	9.11%	11.719	$ 4.130	$ 48.40	35.79%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		465,044	N/A	18,286,174	N/A	N/A	N/A	39 32	37.49%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		465,044		$ 18,286,174				$ 39.32	37 49%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		331,459	N/A	1,954,867	N/A	N/A	N/A	5.90	26.72%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		331,459		$ 1,954,867				$ 5.90	26.72%
	TOTAL PURCHASES		796,503		$ 20,241,041				$ 25.41	64.21%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,240,455		$ 41,728,055				$ 33.64	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,182,355							95.32%
	Sales for Resale		120,209		$ 9,554,083					9.69%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,496							0.12%
	TOTAL @ THE METER		1,304,060							105.13%
	Total Energy Losses *		(63,605)							-5.13%
	Percent Losses *									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	(62)	(619)	$ (11,960)	N/A	-	$ 19.321	$ 192.90	-0.01%
	Nelson 6	385.0	47	497	7,275	N/A	10 574	14.638	154.79	0.00%
	Nelson G & O	646.0	-	-	-	N/A	-	-	-	0.00%
	Sabine	1,890 0	1	17	249	N/A	17.000	14.647	249 00	0.00%
	Willow Glen	2,034.0	-	-	-	N/A	-	-	-	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		(14)	(105)	$ (4,436)		7.500	$ 42.248	$ 316.86	0.00%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month

(2) Other Non-Firm Purchases are net of off-system sales. 193,969 mWh
$ 11,801,845

Control Number: 37856

Item Number: 44

Addendum StartPage: 0

'21 AM 9:57

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF APRIL 2010

Current System Fuel Factor (1)

	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:				
Fuel Cost	501	$ 19,753,341	$ 38,013	$ 19,791,354
Allowances	509	$ 4,867	$ -	$ 4,867
Nuclear Fuel Cost	518	-	-	-
Purchased Power Cost - Nuclear	555	1,506,294	11,358,515	12,864,809
Purchased Power Cost - Non-Nuclear	555	28,834,450	9,186,669	38,021,119
TOTAL SYSTEM COST:		$ 50,098,952	$ 20,583,197	$ 70,682,149
Gains from Disposition of Allowances	411	$ 1,412	$ -	$ 1,412
(2) Sales for Resale Revenue	447	13,324,579	4,808,385	18,132,964
NET SYSTEM COST:		$ 36,772,961	$ 15,774,812	$ 52,547,773
Texas Fixed Fuel Factor Allocator		90.092%	90.092%	90.092%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 33,129,496	$ 14,211,844	$ 47,341,340

	ACCOUNT	REVENUES	MWH SALES
TEXAS FIXED FUEL FACTOR RELATED REVENUES:			
Residential	440	$ 17,669,114	322,951
Commercial & Industrial	442	36,914,484	701,904
Street & Highway	444	379,468	6,936
Public Authorities	445	931,993	17,262
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 55,895,059	1,049,053

	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
OVER/(UNDER) RECOVERY OF COSTS:				
Annual Interest Compound Rate (%):			0.61%	
Beginning Cumulative Balance	182	35,975,783	(8,740,168)	27,235,615
Entry This Month	182	22,765,563	13,806	22,779,369
For Future Use	182	-	-	-
Docket No. 37580 Refund	182	2,927	36	2,963
Ending Cumulative Balance	182	$ 58,744,273	$ (8,726,326)	$ 50,017,947

Comments:

(1) The Texas retail fixed fuel factor is 5.28816 cents/kWh effective with March 2010 billing cycles.

(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs

44

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF APRIL 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No 2	1,473,666	$ 2,574,669	$ 1.747	85,878	$ 29.981	8,580.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	204	3,360	16.471	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	345,629	961,037	2 781	20,411	47.084	8,466.7
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	27,339	184,133	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	-	1,015	-	-	-	-
				TOTAL COAL:	1,846,838	$ 3,724,214	$ 2.017	106,289	$ 35.039	8,687.8
DCP MIDSTREAM	NG	SPOT		Sabine	80,000	$ 338,440	$ 4.231			
ENBRIDGE	NG	SPOT		Sabine	2,530,000	10,183,876	4 025			
KINDER	NG	SPOT		Sabine	100,000	419,251	4.193			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	2,667	(269,150)	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	2,712,667	$ 10,672,417	$ 3.934			
CONOCO	NG	SPOT		Lewis Creek	300,000	$ 1,138,950	$ 3.797			
DCP MIDSTREAM	NG	SPOT		Lewis Creek	20,000	81,634	4 082			
ENBRIDGE	NG	SPOT		Lewis Creek	877,000	3,578,696	4 081			
PACIFIC SUMMIT	NG	SPOT		Lewis Creek	10,000	38,915	3.892			
SEQUENT	NG	SPOT		Lewis Creek	415,000	1,603,200	3.863			
SW ENERGY	NG	SPOT		Lewis Creek	30,000	120,100	4.003			
TAUBER	NG	SPOT		Lewis Creek	100,000	396,850	3 969			
TETCO	NG	SPOT		Lewis Creek	-	109,500	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek			-			
Prior Period Adjustments	NG	N/A		Lewis Creek	34,572	148,697	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	1,786,572	$ 7,216,542	$ 4 039			

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF APRIL 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
	NG	SPOT		Nelson			$ -			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	Oil	SPOT		Nelson			-			
Prior Period Adjustments	NG	N/A		Nelson	-	-	-			
Prior Period Adjustments	Oil	N/A		Nelson	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	NG	SPOT		Willow Glen			$ -			
	Oil	SPOT		Willow Glen	-	-	-			
Prior Period Adjustments	NG	N/A		Willow Glen	-	-	-			
Prior Period Adjustments	Oil	N/A		Willow Glen	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	Oil	SPOT		La. Station	-	-	-			
Prior Period Adjustments	NG	N/A		La. Station	-	-	-			
Prior Period Adjustments	Oil	N/A		La. Station	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
		TOTAL NATURAL GAS & OIL			4,499,239	$ 17,888,959	$ 3.976			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF APRIL 2010

Time Period: 720 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
NUCLEAR:	River Bend 1	697.0	-	-	$ -	0 00%	-	$ -	$ -	0.00%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL NUCLEAR	697.0	-	-	$ -	0.00%	-	$ -	$ -	0.00%
COAL/OIL:	Nelson 6	385.0	(286)	-	$ -	-0 10%	-	$ -	$ -	-0 02%
	Big Cajun No 2 Unit 3	227.0	74,369	732,424	1,318,795	45 50%	9 849	1.801	17 73	5.92%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612 0	74,083	732,424	$ 1,318,795	16.81%	9.887	$ 1.801	$ 17.80	5.90%
GAS/OIL:	Lewis Creek	520 0	155,995	1,752,000	$ 7,067,845	41.67%	11.231	$ 4.034	$ 45.31	12.41%
	Nelson	646.0	-	-	-	0.00%	-	-	-	0.00%
	Sabine	1,890.0	244,688	2,804,871	11,327,127	17.98%	11.463	4.038	46 29	19.47%
	Willow Glen	2,045.0	-	-	-	0.00%	-	-	-	0.00%
	Louisiana Station	140.0	-	-	-	0.00%	-	-	-	0.00%
	Prior Period Adjustments		-	76,627	39,574	-	-	-	-	0.00%
	TOTAL GAS/OIL	5,241 0	400,683	4,633,498	$ 18,434,546	10.62%	11 564	$ 3 979	$ 46.01	31.89%
EMISSIONS & GAINS	509 & 411	-	-	-	3,454	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-		-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 3,454	-	-	$ -	$ -	
	TOTAL NET GENERATION	6,550 0	474,766	5,365,922	$ 19,756,795	10 07%	11.302	$ 3.682	$ 41.61	37.78%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		423,696	N/A	14,246,627	N/A	N/A	N/A	33.62	33.72%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0 00%
	TOTAL COGEN		423,696		$ 14,246,627				$ 33.62	33.72%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		358,142	N/A	2,769,539	N/A	N/A	N/A	7.73	28.50%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		358,142		$ 2,769,539				$ 7 73	28.50%
	TOTAL PURCHASES		781,838		$ 17,016,166				$ 21 76	62.22%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,256,604		$ 36,772,961				$ 29.26	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,094,979							87.14%
	Sales for Resale		76,428							6.08%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,439							0.11%
	TOTAL @ THE METER		1,172,846							93.33%
	Total Energy Losses *		83,758							6.67%
	Percent Losses *									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	(3)	(32)	$ (567)	N/A	-	$ 17.625	$ 189.00	0.00%
	Nelson 6	385 0	-	-	-	N/A	-	-	-	0.00%
	Nelson G & O	646.0	-	-	-	N/A	-	-	-	0.00%
	Sabine	1,890.0	1	14	199	N/A	14.000	14.214	199.00	0.00%
	Willow Glen	2,034.0	-	-	-	N/A	-	-	-	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		(2)	(18)	$ (368)		9.085	$ 20.253	$ 184.00	0.00%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month

(2) Other Non-Firm Purchases are net of off-system sales: 271,913 mWh
$ 13,324,579

Control Number: 37856

Item Number: 54

Addendum StartPage: 0

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF MAY 2010

Current System Fuel Factor (1)

TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
Fuel Cost	501	$ 29,520,246	$ 47,856	$ 29,568,102
Allowances	509	$ 7,673	$ -	$ 7,673
Nuclear Fuel Cost	518	-	-	-
Purchased Power Cost - Nuclear	555	1,716,350	9,295,163	11,011,513
Purchased Power Cost - Non-Nuclear	555	43,701,046	9,803,810	53,504,856
TOTAL SYSTEM COST:		$ 74,945,315	$ 19,146,829	$ 94,092,144
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	16,540,172	35,410,203	51,950,375
NET SYSTEM COST:		$ 58,405,143	$ (16,263,374)	$ 42,141,769
Texas Fixed Fuel Factor Allocator		92.675%	92.675%	92.675%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 54,126,966	$ (15,072,082)	$ 39,054,884

TEXAS FIXED FUEL FACTOR RELATED REVENUES:	ACCOUNT	REVENUES	MWH SALES
Residential	440	$ 20,202,451	369,254
Commercial & Industrial	442	40,324,653	765,957
Street & Highway	444	344,460	6,296
Public Authorities	445	1,000,425	18,542
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 61,871,989	1,160,049

OVER/(UNDER) RECOVERY OF COSTS:	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
Annual Interest Compound Rate (%):			0 61%	
Beginning Cumulative Balance	182	58,744,273	(8,726,326)	50,017,947
Entry This Month	182	7,745,023	25,352	7,770,375
For Future Use	182	-	-	-
Docket No. 37580 Refund	182	-	-	-
Ending Cumulative Balance	182	$ 66,489,296	$ (8,700,974)	$ 57,788,322

Comments:

(1) The Texas retail fixed fuel factor is 5.28816 cents/kWh effective with March 2010 billing cycles.

(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF MAY 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,821,988	$ 3,750,747	$ 2.059	106,668	$ 35.163	8,540 5
Macrol Oil	Igniter Fuel	Firm		Big Cajun No 2	207	3,602	17 401	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	1,040,908	2,708,294	2 602	60,562	44.719	8,593 7
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	(51,958)	161,986	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	3	242	-	-	-	-
				TOTAL COAL:	2,811,148	$ 6,624,871	$ 2.357	167,230	$ 39 615	8,405.0
DCP MIDSTREAM	NG	SPOT		Sabine	470,000	$ 1,993,813	$ 4.242			
ENBRIDGE	NG	SPOT		Sabine	3,100,000	13,266,827	4.280			
JLA ENERGY	NG	SPOT		Sabine	140,000	613,139	4 380			
KINDER	NG	SPOT		Sabine	300,000	1,249,226	4.164			
KMTEJAS	NG	SPOT		Sabine	30,000	128,698	4.290			
NJR	NG	SPOT		Sabine	40,000	166,013	4.150			
ONEOK EM&T	NG	SPOT		Sabine	270,000	1,170,179	4 334			
PACIFIC SUMMIT	NG	SPOT		Sabine	50,000	205,927	4.119			
SEQUENT	NG	SPOT		Sabine	105,000	436,132	4.154			
TAUBER	NG	SPOT		Sabine	70,000	289,219	4.132			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	(89,514)	(174,496)	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	4,485,486	$ 19,344,675	$ 4 313			
DCP MIDSTREAM	NG	SPOT		Lewis Creek	30,000	$ 125,577	$ 4.186			
ENBRIDGE	NG	SPOT		Lewis Creek	810,000	3,470,400	4.284			
JLA ENERGY	NG	SPOT		Lewis Creek	170,000	716,425	4 214			
KMTEJAS	NG	SPOT		Lewis Creek	60,000	240,300	4.005			
PACIFIC SUMMIT	NG	SPOT		Lewis Creek	10,000	41,265	4.127			
SEQUENT	NG	SPOT		Lewis Creek	285,000	1,163,470	4.082			
SW ENERGY	NG	SPOT		Lewis Creek	100,000	404,065	4.041			
TAUBER	NG	SPOT		Lewis Creek	530,000	2,205,595	4.162			
TETCO	NG	SPOT		Lewis Creek	-	109,500	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek			-			
Prior Period Adjustments	NG	N/A		Lewis Creek	34,838	153,711	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	2,029,838	$ 8,630,308	$ 4.252			

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF MAY 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
	NG	SPOT		Nelson			$ -			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	Oil	SPOT		Nelson			-			
Prior Period Adjustments	NG	N/A		Nelson	-	-	-			
Prior Period Adjustments	Oil	N/A		Nelson	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	NG	SPOT		Willow Glen			$ -			
	Oil	SPOT		Willow Glen	-	-	-			
Prior Period Adjustments	NG	N/A		Willow Glen	-	-	-			
Prior Period Adjustments	Oil	N/A		Willow Glen	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	Oil	SPOT		La Station	-	-	-			
Prior Period Adjustments	NG	N/A		La. Station	-	-	-			
Prior Period Adjustments	Oil	N/A		La. Station	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
		TOTAL NATURAL GAS & OIL			6,515,324	$ 27,974,983	$ 4.294			

Comments. (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF MAY 2010

Time Period: 744 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
NUCLEAR:	River Bend 1	697.0	-	-	$ -	0.00%	-	$ -	$ -	0.00%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL NUCLEAR	697.0	-	-	$ -	0.00%	-	$ -	$ -	0.00%
COAL/OIL:	Nelson 6	385.0	10,921	139,491	$ 370,824	3.81%	12.773	$ 2.658	$ 33.96	0.67%
	Big Cajun No. 2 Unit 3	227.0	76,439	760,956	1,406,067	45.26%	9.955	1.848	18.39	4.67%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	87,360	900,447	$ 1,776,891	19.19%	10.307	$ 1.973	$ 20.34	5.34%
GAS/OIL:	Lewis Creek	520.0	185,038	1,995,000	$ 8,476,597	47.83%	10.782	$ 4.249	$ 45.81	11 30%
	Nelson	646.0	-	-	-	0 00%	-	-	-	0.00%
	Sabine	1,890.0	410,506	4,394,285	18,786,317	29.19%	10.705	4.275	45.76	25.08%
	Willow Glen	2,045.0	-	-	-	0.00%	-	-	-	0.00%
	Louisiana Station	140.0	-	-	-	0.00%	-	-	-	0.00%
	Prior Period Adjustments		-	68,737	480,442	-	-	-	-	0.00%
	TOTAL GAS/OIL	5,241.0	595,544	6,458,022	$ 27,743,356	15.27%	10.844	$ 4.296	$ 46.58	36.38%
EMISSIONS & GAINS	509 & 411	-	-	-	7,673	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 7,673	-	-	$ -	$ -	
	TOTAL NET GENERATION	6,550.0	682,904	7,358,469	$ 29,527,920	14.01%	10.775	$ 4.013	$ 43.24	41.72%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		230,072	N/A	8,145,928	N/A	N/A	N/A	35.41	14.05%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		230,072		$ 8,145,928				$ 35.41	14.05%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		724,039	N/A	20,731,295	N/A	N/A	N/A	28.63	44.23%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		724,039		$ 20,731,295				$ 28.63	44.23%
	TOTAL PURCHASES		954,111		$ 28,877,223				$ 30.27	58.28%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,637,015		$ 58,405,143				$ 35.68	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,202,776							73.47%
	Sales for Resale		56,458							3.45%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,449							0 09%
	TOTAL @ THE METER		1,260,683							77.01%
	Total Energy Losses *		376,332							22.99%
	Percent Losses *									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227 0	13	127	$ 2,411	N/A	9.778	$ 18 968	$ 185.46	0.00%
	Nelson 6	385.0	147	1,882	27,539	N/A	12 802	14.634	187 34	0.01%
	Nelson G & O	646.0	-	-	-	N/A	-	-	-	0.00%
	Sabine	1,890.0	5	55	806	N/A	11.000	14.655	161.20	0.00%
	Willow Glen	2,034.0	-	-	-	N/A	-	-	-	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0 00%
	TOTAL OIL		165	2,064	$ 30,756		12.509	$ 14.901	$ 186.40	0.01%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

(2) Other Non-Firm Purchases are net of off-system sales 345,893 mWh
$ 16,540,172

Control Number: 37856

Item Number: 68

Addendum StartPage: 0

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF JUNE 2010

Current System Fuel Factor (1)

	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:				
Fuel Cost	501	$ 41,481,758	$ 201,671	$ 41,683,429
Allowances	509	$ (236,944)	$ -	$ (236,944)
Nuclear Fuel Cost	518	-	-	-
Purchased Power Cost - Nuclear	555	1,602,412	8,385,171	9,987,583
Purchased Power Cost - Non-Nuclear	555	53,456,631	10,036,237	63,492,868
TOTAL SYSTEM COST:		$ 96,303,857	$ 18,623,079	$ 114,926,936
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	21,204,866	42,040,230	63,245,096
NET SYSTEM COST:		$ 75,098,991	$ (23,417,151)	$ 51,681,840
Texas Fixed Fuel Factor Allocator		91 091%	91.091%	91 091%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 68,408,422	$ (21,330,917)	$ 47,077,505

	ACCOUNT	REVENUES	MWH SALES
TEXAS FIXED FUEL FACTOR RELATED REVENUES:			
Residential	440	$ 30,390,078	555,461
Commercial & Industrial	442	43,932,421	832,227
Street & Highway	444	286,547	5,237
Public Authorities	445	1,097,080	20,351
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 75,706,126	1,413,276

	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
OVER/(UNDER) RECOVERY OF COSTS:				
Annual Interest Compound Rate (%).			0.61%	
Beginning Cumulative Balance	182	66,489,296	(8,700,974)	57,788,322
Entry This Month	182	7,297,704	29,294	7,326,998
For Future Use	182	-	-	-
Docket No. 37580 Refund	182	-	-	-
Ending Cumulative Balance	182	$ 73,787,000	$ (8,671,680)	$ 65,115,320

Comments:

(1) The Texas retail fixed fuel factor is 5.28816 cents/kWh effective with March 2010 billing cycles

(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

68

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF JUNE 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No 2	1,368,266	$ 2,790,665	$ 2 040	80,638	$ 34.607	8,484.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	7	97	13 857	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	1,559,900	4,098,416	2.627	91,739	44.675	8,501.8
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	(51,958)	349,403	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	(200)	(3,505)	-	-	-	-
				TOTAL COAL:	2,876,015	$ 7,235,076	$ 2.516	172,377	$ 41.972	8,342.2
DCP MIDSTREAM	NG	SPOT		Sabine	1,480,000	$ 6,822,909	$ 4 610			
ENBRIDGE	NG	SPOT		Sabine	2,700,000	12,029,353	4 455			
JLA ENERGY	NG	SPOT		Sabine	250,000	1,251,623	5 006			
KINDER	NG	SPOT		Sabine	150,000	692,114	4.614			
KMTEJAS	NG	SPOT		Sabine	380,000	1,936,356	5.096			
NJR	NG	SPOT		Sabine	85,000	424,894	4.999			
NOBLE	NG	SPOT		Sabine	14,447	72,625	5.027			
ONEOK EM&T	NG	SPOT		Sabine	490,000	2,352,206	4.800			
SEQUENT	NG	SPOT		Sabine	60,000	318,120	5.302			
TAUBER	NG	SPOT		Sabine	80,000	392,560	4 907			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	3,219	(108,319)	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	5,692,666	$ 26,184,441	$ 4 600			
ENBRIDGE	NG	SPOT		Lewis Creek	900,000	$ 3,973,500	$ 4.415			
JLA ENERGY	NG	SPOT		Lewis Creek	455,000	2,223,175	4 886			
PACIFIC SUMMIT	NG	SPOT		Lewis Creek	60,000	302,090	5.035			
SEQUENT	NG	SPOT		Lewis Creek	580,000	2,562,860	4.419			
SW ENERGY	NG	SPOT		Lewis Creek	45,000	208,125	4 625			
TAUBER	NG	SPOT		Lewis Creek	300,000	1,424,850	4.750			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek			-			
Prior Period Adjustments	NG	N/A		Lewis Creek	16,344	96,532	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	2,356,344	$ 10,791,132	$ 4.580			

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF JUNE 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
	NG	SPOT		Nelson			$ -			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	Oil	SPOT		Nelson			-			
Prior Period Adjustments	NG	N/A		Nelson	-	-	-			
Prior Period Adjustments	Oil	N/A		Nelson	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	NG	SPOT		Willow Glen			$ -			
	Oil	SPOT		Willow Glen	-	-	-			
Prior Period Adjustments	NG	N/A		Willow Glen	-	-	-			
Prior Period Adjustments	Oil	N/A		Willow Glen	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	Oil	SPOT		La. Station	-	-	-			
Prior Period Adjustments	NG	N/A		La Station	-	-	-			
Prior Period Adjustments	Oil	N/A		La Station	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
		TOTAL NATURAL GAS & OIL			8,049,010	$ 36,975,573	$ 4.594			

Comments (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF JUNE 2010

Time Period: 720 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
NUCLEAR:	River Bend 1	697 0	-	-	$ -	0.00%	-	$ -	$ -	0 00%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL NUCLEAR	697.0	-	-	$ -	0.00%	-	$ -	$ -	0.00%
COAL/OIL:	Nelson 6	385.0	114,776	1,225,475	$ 3,173,826	41.41%	10.677	$ 2.590	$ 27.65	6.34%
	Big Cajun No. 2 Unit 3	227 0	75,178	762,960	1,430,518	46.00%	10 149	1 875	19.03	4.15%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	189,954	1,988,435	$ 4,604,344	43.11%	10 468	$ 2.316	$ 24 24	10.49%
GAS/OIL:	Lewis Creek	520 0	212,861	2,340,000	$ 10,694,600	56.85%	10.993	$ 4.570	$ 50.24	11.75%
	Nelson	646 0	-	-	-	0.00%	-	-	-	0.00%
	Sabine	1,890.0	494,979	5,552,319	25,726,909	36.37%	11.217	4.634	51.98	27 33%
	Willow Glen	2,045 0	-	-	-	0 00%	-	-	-	0.00%
	Louisiana Station	140.0	-	-	-	0.00%	-	-	-	0.00%
	Prior Period Adjustments		-	133,741	455,905	-	-	-	-	0.00%
	TOTAL GAS/OIL	5,241.0	707,840	8,026,060	$ 36,877,414	18.76%	11.339	$ 4.595	$ 52.10	39 08%
EMISSIONS & GAINS	509 & 411	-	-	-	(236,944)	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-		-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ (236,944)	-	-	$ -	$ -	
	TOTAL NET GENERATION	6,550.0	897,794	10,014,495	$ 41,244,814	19.04%	11.155	$ 4.119	$ 45.94	49.56%
PURCHASES:	Firm Cogen (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		171,324	N/A	7,032,868	N/A	N/A	N/A	41.05	9.46%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		171,324		$ 7,032,868				$ 41.05	9 46%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		742,326	N/A	26,821,309	N/A	N/A	N/A	36.13	40.98%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		742,326		$ 26,821,309				$ 36 13	40.98%
	TOTAL PURCHASES		913,650		$ 33,854,177				$ 37.05	50.44%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,811,444		$ 75,098,991				$ 41.46	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,463,107							80 77%
	Sales for Resale		97,682							5.39%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,782							0 10%
	TOTAL @ THE METER		1,562,571							86.26%
	Total Energy Losses *		248,873							13 74%
	Percent Losses *									
FUEL OIL: (Included in the above generation)										
	Big Cajun No 2 Unit 3	227.0	(5)	(48)	$ 4,643	N/A	-	$ (97.073)	$ (928.60)	0 00%
	Nelson 6	385.0	68	726	10,619	N/A	10.671	14 634	156.16	0.00%
	Nelson G & O	646.0	-	-	-	N/A	-	-	-	0.00%
	Sabine	1,890.0	3	34	504	N/A	11.333	14.824	168 00	0.00%
	Willow Glen	2,034.0	-	-	-	N/A	-	-	-	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		66	712	$ 15,766		10 785	$ 22 149	$ 238.88	0.00%

Utilities Notes:
(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month
(2) Other Non-Firm Purchases are net of off-system sales 406,055 mWh
$ 21,204,866

Control Number: 37856

Item Number: 69

Addendum StartPage: 0

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF JULY 2010

Current System Fuel Factor: (1)

	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:				
Fuel Cost	501	$ 43,781,823	$ 161,440	$ 43,943,263
Allowances	509	$ (83,290)	$ -	$ (83,290)
Nuclear Fuel Cost	518	-	-	-
Purchased Power Cost - Nuclear	555	1,617,951	9,721,322	11,339,273
Purchased Power Cost - Non-Nuclear	555	55,385,261	10,456,018	65,841,279
TOTAL SYSTEM COST:		$ 100,701,745	$ 20,338,780	$ 121,040,525
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	23,234,682	32,570,254	55,804,936
NET SYSTEM COST:		$ 77,467,063	$ (12,231,474)	$ 65,235,589
Texas Fixed Fuel Factor Allocator		90.900%	90.900%	90.900%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 70,417,560	$ (11,118,410)	$ 59,299,150

	ACCOUNT	REVENUES	MWH SALES
TEXAS FIXED FUEL FACTOR RELATED REVENUES:			
Residential	440	$ 35,304,582	645,286
Commercial & Industrial	442	44,902,688	849,732
Street & Highway	444	358,225	6,548
Public Authorities	445	1,102,457	20,455
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 81,667,952	1,522,021

	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
OVER/(UNDER) RECOVERY OF COSTS:				
Annual Interest Compound Rate (%):			0.61%	
Beginning Cumulative Balance	182	73,787,000	(8,671,680)	65,115,320
Entry This Month	182	11,250,392	33,008	11,283,400
For Future Use	182	-	-	-
Docket No. 37580 Refund	182	-	-	-
Ending Cumulative Balance	182	$ 85,037,392	$ (8,638,672)	$ 76,398,720

Comments:
(1) The Texas retail fixed fuel factor is 5 28816 cents/kWh effective with March 2010 billing cycles.
(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs

69

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF JULY 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,093,895	$ 2,261,348	$ 2.067	65,276	$ 34.643	8,379.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	4	56	14.000	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	3,013,693	7,751,601	2.572	173,611	44.649	8,679.4
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	(79,297)	132,073	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	(3)	(41)	-	-	-	-
				TOTAL COAL:	4,028,292	$ 10,145,037	$ 2.518	238,887	$ 42.468	8,431.4
CENTERPOINT	NG	SPOT		Sabine	10,000	$ 47,563	$ 4.756			
DCP MIDSTREAM	NG	SPOT		Sabine	1,430,000	6,885,587	4.815			
ENBRIDGE	NG	SPOT		Sabine	2,880,581	13,602,317	4.722			
JLA ENERGY	NG	SPOT		Sabine	20,000	99,926	4.996			
KMTEJAS	NG	SPOT		Sabine	1,400,000	6,738,148	4.813			
ONEOK EM&T	NG	SPOT		Sabine	340,000	1,590,449	4.678			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	(2,775)	(753,463)	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	6,077,806	$ 28,210,527	$ 4.642			
ENBRIDGE	NG	SPOT		Lewis Creek	870,000	$ 4,160,047	$ 4.782			
IBERDROLA	NG	SPOT		Lewis Creek	5,000	24,585	4.917			
JLA ENERGY	NG	SPOT		Lewis Creek	165,000	767,550	4.652			
KMTEJAS	NG	SPOT		Lewis Creek	40,000	187,200	4.680			
NJR	NG	SPOT		Lewis Creek	620,000	2,951,634	4.761			
SEQUENT	NG	SPOT		Lewis Creek	215,000	1,011,009	4.702			
SW ENERGY	NG	SPOT		Lewis Creek	120,000	541,900	4.516			
TAUBER	NG	SPOT		Lewis Creek	240,000	1,094,060	4.559			
TETCO	NG	SPOT		Lewis Creek	-	109,500	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek			-			
Prior Period Adjustments	NG	N/A		Lewis Creek	(19,354)	49,414	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	2,255,646	$ 10,896,898	$ 4.831			

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF JULY 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
	NG	SPOT		Nelson			$ -			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	Oil	SPOT		Nelson			-			
Prior Period Adjustments	NG	N/A		Nelson	-	-	-			
Prior Period Adjustments	Oil	N/A		Nelson	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	NG	SPOT		Willow Glen			$ -			
	Oil	SPOT		Willow Glen	-	-	-			
Prior Period Adjustments	NG	N/A		Willow Glen	-	-	-			
Prior Period Adjustments	Oil	N/A		Willow Glen	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	Oil	SPOT		La. Station	-	-	-			
Prior Period Adjustments	NG	N/A		La. Station	-	-	-			
Prior Period Adjustments	Oil	N/A		La. Station	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
		TOTAL NATURAL GAS & OIL			8,333,452	$ 39,107,425	$ 4.693			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF JULY 2010

Time Period· 744 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
NUCLEAR:	River Bend 1	697.0	-	-	$ -	0.00%	-	$ -	$ -	0.00%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL NUCLEAR	697.0	-	-	$ -	0.00%	-	$ -	$ -	0.00%
COAL/OIL:	Nelson 6	385.0	111,932	1,186,631	$ 3,087,878	39 08%	10 601	$ 2.602	$ 27 59	5.91%
	Big Cajun No. 2 Unit 3	227.0	70,924	730,030	1,371,800	41.99%	10.293	1.879	19.34	3.75%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	182,856	1,916,661	$ 4,459,678	40.16%	10.482	$ 2.327	$ 24.39	9.66%
GAS/OIL:	Lewis Creek	520 0	218,700	2,275,000	$ 10,847,484	56 53%	10 402	$ 4.768	$ 49 60	11.55%
	Nelson	646.0	-	-	-	0.00%	-	-	-	0.00%
	Sabine	1,890.0	572,167	6,162,402	29,296,894	40.69%	10.770	4.754	51.20	30.22%
	Willow Glen	2,045.0	-	-	-	0.00%	-	-	-	0 00%
	Louisiana Station	140.0	-	-	-	0 00%	-	-	-	0.00%
	Prior Period Adjustments		-	(50,458)	(822,234)	-	-	-	-	0.00%
	TOTAL GAS/OIL	5,241.0	790,867	8,386,944	$ 39,322,144	20.28%	10.605	$ 4 688	$ 49.72	41.77%
EMISSIONS & GAINS	509 & 411	-	-	-	(83,290)	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0 00%
		-	-	-		-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ (83,290)	-	-	$ -	$ -	
	TOTAL NET GENERATION	6,550.0	973,723	10,303,605	$ 43,698,532	19.98%	10.582	$ 4.241	$ 44.88	51.42%
PURCHASES:	Firm Cogen. (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		185,758	N/A	7,684,365	N/A	N/A	N/A	41.37	9.81%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		185,758		$ 7,684,365				$ 41.37	9.81%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0 00%
	Other Non-Firm (2)		734,064	N/A	26,084,166	N/A	N/A	N/A	35.53	38.77%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		734,064		$ 26,084,166				$ 35 53	38.77%
	TOTAL PURCHASES		919,822		$ 33,768,531				$ 36.71	48.58%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0 00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,893,545		$ 77,467,063				$ 40.91	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,570,104							82.92%
	Sales for Resale		114,327							6.04%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,706							0.09%
	TOTAL @ THE METER		1,686,137							89.05%
	Total Energy Losses *		207,408							10.95%
	Percent Losses *									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	(15)	(150)	$ (711)	N/A	-	$ 4.729	$ 47 40	0 00%
	Nelson 6	385.0	35	373	5,463	N/A	10 665	14.635	156.09	0.00%
	Nelson G & O	646.0	-	-	-	N/A	-	-	-	0.00%
	Sabine	1,890 0	4	41	604	N/A	10.250	14.732	151.00	0.00%
	Willow Glen	2,034.0	-	-	-	N/A	-	-	-	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		24	264	$ 5,356		10.998	$ 20.292	$ 223.17	0.00%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

(2) Other Non-Firm Purchases are net of off-system sales 459,562 mWh
$ 23,234,682

Control Number: 37856

Item Number: 95

Addendum StartPage: 0

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PUBLIC UTILITY COMMISSION
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PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF AUGUST 2010

Current System Fuel Factor: (1)

TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
Fuel Cost	501	$ 47,422,812	$ 141,088	$ 47,563,900
Allowances	509	$ 10,909	$ -	$ 10,909
Nuclear Fuel Cost	518	-	-	-
Purchased Power Cost - Nuclear	555	2,044,376	10,933,041	12,977,417
Purchased Power Cost - Non-Nuclear	555	65,583,778	11,482,681	77,066,459
TOTAL SYSTEM COST:		$ 115,061,875	$ 22,556,810	$ 137,618,685
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	23,898,490	29,141,541	53,040,031
NET SYSTEM COST:		$ 91,163,385	$ (6,584,731)	$ 84,578,654
Texas Fixed Fuel Factor Allocator		89.950%	89.950%	89.950%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 82,001,465	$ (5,922,966)	$ 76,078,499

TEXAS FIXED FUEL FACTOR RELATED REVENUES:	ACCOUNT	REVENUES	MWH SALES
Residential	440	$ 35,682,767	652,199
Commercial & Industrial	442	46,022,492	871,835
Street & Highway	444	359,055	6,563
Public Authorities	445	1,147,334	21,273
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 83,211,648	1,551,870

OVER/(UNDER) RECOVERY OF COSTS:	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
Annual Interest Compound Rate (%):			0.61%	
Beginning Cumulative Balance	182	85,037,392	(8,638,672)	76,398,720
Entry This Month	182	1,210,183	38,728	1,248,911
For Future Use	182	-	-	-
Docket No 37580 Refund	182	-	-	-
Ending Cumulative Balance	182	$ 86,247,575	$ (8,599,944)	$ 77,647,631

Comments:
(1) The Texas retail fixed fuel factor is 5 28816 cents/kWh effective with March 2010 billing cycles
(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs

95

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF AUGUST 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No 2	1,093,895	$ 2,276,681	$ 2.081	65,276	$ 34.878	8,379.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	254	4,140	16.299	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	2,816,290	7,253,104	2.575	162,412	44.659	8,670.2
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	(79,297)	132,470	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	250	4,085	-	-	-	-
				TOTAL COAL:	3,831,392	$ 9,670,480	$ 2.524	227,688	$ 42.473	8,413.7
CENTERPOINT	NG	SPOT		Sabine	15,000	$ 73,066	$ 4.871			
DCP MIDSTREAM	NG	SPOT		Sabine	1,490,000	7,026,371	4.716			
ENBRIDGE	NG	SPOT		Sabine	2,760,000	12,630,687	4.576			
JLA ENERGY	NG	SPOT		Sabine	470,000	2,063,421	4.390			
KMTEJAS	NG	SPOT		Sabine	1,390,000	6,576,566	4.731			
ONEOK EM&T	NG	SPOT		Sabine	475,000	2,239,051	4.714			
SEQUENT	NG	SPOT		Sabine	85,000	387,806	4.562			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	(17,895)	888,470	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	6,667,105	$ 31,885,437	$ 4.783			
ENBRIDGE	NG	SPOT		Lewis Creek	850,000	$ 3,966,248	$ 4.666			
JLA ENERGY	NG	SPOT		Lewis Creek	60,000	268,700	4.478			
KMTEJAS	NG	SPOT		Lewis Creek	20,000	91,700	4.585			
NJR	NG	SPOT		Lewis Creek	620,000	2,889,634	4.661			
SEQUENT	NG	SPOT		Lewis Creek	320,000	1,428,283	4.463			
SW ENERGY	NG	SPOT		Lewis Creek	205,000	872,600	4.257			
TAUBER	NG	SPOT		Lewis Creek	240,000	1,060,710	4.420			
TETCO	NG	SPOT		Lewis Creek	-	109,500	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek			-			
Prior Period Adjustments	NG	N/A		Lewis Creek	100,812	458,943	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	2,415,812	$ 11,146,318	$ 4.614			

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF AUGUST 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
	NG	SPOT		Nelson			$ -			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	Oil	SPOT		Nelson			-			
Prior Period Adjustments	NG	N/A		Nelson	-	-	-			
Prior Period Adjustments	Oil	N/A		Nelson	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	NG	SPOT		Willow Glen			$ -			
	Oil	SPOT		Willow Glen	-	-	-			
Prior Period Adjustments	NG	N/A		Willow Glen	-	-	-			
Prior Period Adjustments	Oil	N/A		Willow Glen	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	Oil	SPOT		La. Station	-	-	-			
Prior Period Adjustments	NG	N/A		La. Station	-	-	-			
Prior Period Adjustments	Oil	N/A		La. Station	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
		TOTAL NATURAL GAS & OIL			9,082,917	$ 43,031,755	$ 4.738			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF AUGUST 2010

Time Period· 744 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
NUCLEAR:	River Bend 1	697.0	-	-	$ -	0 00%	-	$ -	$ -	0.00%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL NUCLEAR	697.0	-	-	$ -	0.00%	-	$ -	$ -	0.00%
COAL/OIL:	Nelson 6	385.0	109,577	1,208,056	$ 3,163,014	38.25%	11.025	$ 2.618	$ 28.87	5.44%
	Big Cajun No. 2 Unit 3	227.0	73,303	756,704	1,463,786	43.40%	10.323	1.934	19.97	3.64%
	Prior Period Adjustments		-	115	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	182,880	1,964,875	$ 4,626,800	40.16%	10.744	$ 2.355	$ 25.30	9.07%
GAS/OIL:	Lewis Creek	520.0	213,343	2,315,000	$ 10,687,375	55.14%	10 851	$ 4.617	$ 50.09	10.59%
	Nelson	646.0	-	-	-	0 00%	-	-	-	0.00%
	Sabine	1,890.0	602,426	6,491,230	30,230,358	42 84%	10.775	4.657	50.18	29.89%
	Willow Glen	2,045.0	-	-	-	0 00%	-	-	-	0.00%
	Louisiana Station	140.0	-	-	-	0.00%	-	-	-	0.00%
	Prior Period Adjustments		-	213,644	1,878,280	-	-	-	-	0.00%
	TOTAL GAS/OIL	5,241.0	815,769	9,019,874	$ 42,796,013	20 92%	11.057	$ 4.745	$ 52.46	40.48%
EMISSIONS & GAINS	509 & 411	-	-	-	10,909	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 10,909	-	-	$ -	$ -	
	TOTAL NET GENERATION	6,550.0	998,649	10,984,749	$ 47,433,722	20.49%	11.000	$ 4.318	$ 47.50	49.55%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		195,613	N/A	7,827,470	N/A	N/A	N/A	40.02	9.71%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0 00%
	TOTAL COGEN		195,613		$ 7,827,470				$ 40.02	9.71%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		821,148	N/A	35,902,193	N/A	N/A	N/A	43.72	40.74%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		821,148		$ 35,902,193				$ 43.72	40.74%
	TOTAL PURCHASES		1,016,761		$ 43,729,663				$ 43.01	50.45%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		2,015,410		$ 91,163,385				$ 45.23	100 00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,612,350							80.00%
	Sales for Resale		123,250							6.12%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,744							0.09%
	TOTAL @ THE METER		1,737,344							86.21%
	Total Energy Losses *		278,066							13.79%
	Percent Losses *									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	186	1,804	$ 34,574	N/A	9 698	$ 19.167	$ 185.88	0.01%
	Nelson 6	385.0	74	821	12,018	N/A	11 098	14.634	162.41	0.00%
	Nelson G & O	646.0	-	-	-	N/A	-	-	-	0.00%
	Sabine	1,890.0	6	62	905	N/A	10.333	14.597	150.83	0.00%
	Willow Glen	2,034.0	-	-	-	N/A	-	-	-	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0 00%
	TOTAL OIL		266	2,687	$ 47,497		10.102	$ 17.676	$ 178.56	0.01%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month

(2) Other Non-Firm Purchases are net of off-system sales 477,407 mWh
$ 23,898,490

Control Number: 37856

Item Number: 103

Addendum StartPage: 0

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PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF SEPTEMBER 2010

Current System Fuel Factor: (1)

	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:				
Fuel Cost	501	$ 29,061,930	$ 142,601	$ 29,204,531
Allowances	509	$ 7,542	$ -	$ 7,542
Nuclear Fuel Cost	518	-	-	-
Purchased Power Cost - Nuclear	555	2,103,309	10,058,953	12,162,262
Purchased Power Cost - Non-Nuclear	555	40,019,326	9,822,463	49,841,789
TOTAL SYSTEM COST:		$ 71,192,107	$ 20,024,017	$ 91,216,124
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	15,396,167	4,505,601	19,901,768
NET SYSTEM COST:		$ 55,795,940	$ 15,518,416	$ 71,314,356
Texas Fixed Fuel Factor Allocator		89.492%	89.492%	89.492%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 49,932,903	$ 13,887,741	$ 63,820,644

	ACCOUNT	REVENUES	MWH SALES
TEXAS FIXED FUEL FACTOR RELATED REVENUES:			
Residential	440	$ 30,065,426	653,765
Commercial & Industrial	442	39,424,947	888,034
Street & Highway	444	303,246	6,594
Public Authorities	445	987,822	21,788
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 70,781,441	1,570,181

	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
OVER/(UNDER) RECOVERY OF COSTS:				
		Annual Interest Compound Rate (%).	0.61%	
Beginning Cumulative Balance	182	86,247,575	(8,599,944)	77,647,631
Entry This Month	182	20,848,538	39,361	20,887,899
Docket No. 37744 Settlement	182	3,250,000	225,835	3,475,835
Docket No. 38403 Refund	182	(46,314,839)	(306,582)	(46,621,421)
Ending Cumulative Balance	182	$ 64,031,274	$ (8,641,330)	$ 55,389,944

Comments:

(1) The Texas retail fixed fuel factor is 4.44500 cents/kWh effective with September 2010 billing cycles.
(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF SEPTEMBER 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	976,219	$ 2,065,270	$ 2.116	57,984	$ 35 618	8,418.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	2,890	48,241	16.692	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	2,803,746	7,205,508	2 570	162,737	44.277	8,614.3
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	(79,297)	187,148	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	2,636	44,101	-	-	-	-
				TOTAL COAL:	3,706,194	$ 9,550,268	$ 2 577	220,721	$ 43.269	8,395.7
CNG	NG	SPOT		Sabine	300,000	$ 1,142,947	$ 3.810			
DCP MIDSTREAM	NG	SPOT		Sabine	1,090,000	4,168,757	3.825			
ENBRIDGE	NG	SPOT		Sabine	2,321,918	8,923,586	3.843			
ETC MARKETING	NG	SPOT		Sabine	20,000	78,496	3.925			
JLA ENERGY	NG	SPOT		Sabine	490,000	1,941,913	3.963			
KMTEJAS	NG	SPOT		Sabine	35,000	139,594	3.988			
ONEOK EM&T	NG	SPOT		Sabine	20,000	78,696	3.935			
SEQUENT	NG	SPOT		Sabine	300,000	1,198,947	3.996			
TAUBER	NG	SPOT		Sabine	20,000	76,897	3.845			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	(16,204)	(436,483)	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	4,580,714	$ 17,313,351	$ 3.780			
ENBRIDGE	NG	SPOT		Lewis Creek	735,000	$ 2,857,270	$ 3 887			
JLA ENERGY	NG	SPOT		Lewis Creek	170,000	682,150	4.013			
KINDER	NG	SPOT		Lewis Creek	20,000	84,900	4 245			
KMTEJAS	NG	SPOT		Lewis Creek	40,000	163,200	4.080			
NJR	NG	SPOT		Lewis Creek	580,000	2,188,606	3.773			
SW ENERGY	NG	SPOT		Lewis Creek	95,000	383,050	4.032			
TAUBER	NG	SPOT		Lewis Creek	290,000	1,033,835	3.565			
TETCO	NG	SPOT		Lewis Creek	-	109,500	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek			-			
Prior Period Adjustments	NG	N/A		Lewis Creek	55,271	231,328	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	1,985,271	$ 7,733,839	$ 3.896			

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF SEPTEMBER 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
	NG	SPOT		Nelson			$ -			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	NG	SPOT		Nelson			-			
	Oil	SPOT		Nelson			-			
Prior Period Adjustments	NG	N/A		Nelson	-	-	-			
Prior Period Adjustments	Oil	N/A		Nelson	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	NG	SPOT		Willow Glen			$ -			
	Oil	SPOT		Willow Glen	-	-	-			
Prior Period Adjustments	NG	N/A		Willow Glen	-	-	-			
Prior Period Adjustments	Oil	N/A		Willow Glen	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
	Oil	SPOT		La Station	-	-	-			
Prior Period Adjustments	NG	N/A		La. Station	-	-	-			
Prior Period Adjustments	Oil	N/A		La. Station	-	-	-			
				TOTAL PLANT:	-	$ -	$ -			
				TOTAL NATURAL GAS & OIL	6,565,985	$ 25,047,190	$ 3.815			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF SEPTEMBER 2010

Time Period: 720 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
NUCLEAR:	River Bend 1	697 0	-	-	$ -	0.00%	-	$ -	$ -	0 00%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL NUCLEAR	697.0	-	-	$ -	0.00%	-	$ -	$ -	0.00%
COAL/OIL:	Nelson 6	385.0	80,343	926,600	$ 2,485,612	28.98%	11.533	$ 2 683	$ 30.94	4 77%
	Big Cajun No. 2 Unit 3	227.0	72,961	781,010	1,508,913	44.64%	10.704	1.932	20 68	4.33%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	153,304	1,707,610	$ 3,994,525	34.79%	11.139	$ 2.339	$ 26.06	9.10%
GAS/OIL:	Lewis Creek	520.0	169,194	1,929,259	$ 7,499,501	45.19%	11.403	$ 3 887	$ 44.32	10.05%
	Nelson	646.0	-	-	-	0.00%	-	-	-	0.00%
	Sabine	1,890.0	386,123	4,454,642	17,215,209	28.37%	11 537	3.865	44.58	22 92%
	Willow Glen	2,045.0	-	-	-	0.00%	-	-	-	0.00%
	Louisiana Station	140.0	-	-	-	0.00%	-	-	-	0.00%
	Prior Period Adjustments		-	177,769	352,694	-	-	-	-	0.00%
	TOTAL GAS/OIL	5,241.0	555,317	6,561,670	$ 25,067,404	14.72%	11.816	$ 3.820	$ 45.14	32.97%
EMISSIONS & GAINS	509 & 411	-	-	-	7,542	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 7,542	-	-	$ -	$ -	
	TOTAL NET GENERATION	6,550.0	708,621	8,269,280	$ 29,069,471	15.03%	11.670	$ 3.515	$ 41.02	42 07%
PURCHASES:	Firm Cogen (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0 00%
	Non-Firm Cogen		342,682	N/A	11,391,253	N/A	N/A	N/A	33.24	20.35%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		342,682		$ 11,391,253				$ 33.24	20.35%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		633,086	N/A	15,335,216	N/A	N/A	N/A	24.22	37.59%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		633,086		$ 15,335,216				$ 24.22	37.59%
	TOTAL PURCHASES		975,768		$ 26,726,469				$ 27.39	57 93%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,684,389		$ 55,795,940				$ 33.13	100 00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,622,938							96.35%
	Sales for Resale		142,118							8.44%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,751							0.10%
	TOTAL @ THE METER		1,766,807							104.89%
	Total Energy Losses *		(82,418)							-4.89%
	Percent Losses *									
FUEL OIL: (Included in the above generation)										
	Big Cajun No 2 Unit 3	227.0	261	2,794	$ 50,403	N/A	10.704	$ 18 041	$ 193 11	0.02%
	Nelson 6	385 0	454	5,232	76,566	N/A	11.524	14.634	168.65	0.03%
	Nelson G & O	646.0	-	-	-	N/A	-	-	-	0.00%
	Sabine	1,890.0	2	28	413	N/A	14 000	14.750	206.50	0.00%
	Willow Glen	2,034.0	-	-	-	N/A	-	-	-	0 00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		717	8,054	$ 127,382		11.233	$ 15.816	$ 177.66	0.04%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month

(2) Other Non-Firm Purchases are net of off-system sales 321,561 mWh
$ 15,396,167

Control Number: 37856

Item Number: 109

Addendum StartPage: 0

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF OCTOBER 2010

Current System Fuel Factor: (1)

	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:				
Fuel Cost	501	$ 28,822,068	$ 163,219	$ 28,985,287
Allowances	509	$ 6,830	$ -	$ 6,830
Purchased Power Cost - Nuclear	555	1,932,141	10,164,424	12,096,565
Purchased Power Cost - Non-Nuclear	555	11,290,720	10,464,882	21,755,602
TOTAL SYSTEM COST:		$ 42,051,759	$ 20,792,525	$ 62,844,284
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	14,087,091	7,954,560	22,041,651
NET SYSTEM COST:		$ 27,964,668	$ 12,837,965	$ 40,802,633
Texas Fixed Fuel Factor Allocator		91.922%	91.922%	91.922%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 25,705,682	$ 11,800,914	$ 37,506,596

	ACCOUNT	REVENUES	MWH SALES
TEXAS FIXED FUEL FACTOR RELATED REVENUES:			
Residential	440	$ 22,212,399	483,003
Commercial & Industrial	442	36,921,300	833,346
Street & Highway	444	303,877	6,608
Public Authorities	445	919,805	20,311
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 60,357,381	1,343,268

	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
OVER/(UNDER) RECOVERY OF COSTS:				
Annual Interest Compound Rate (%):			0.61%	
Beginning Cumulative Balance	182	64,031,274	(8,641,330)	55,389,944
Entry This Month	182	34,651,699	28,078	34,679,777
Docket No. 38403 Refund	182	(18,222,254)	(120,623)	(18,342,877)
Docket No. 38098 True-up	182	(3,449,293)		(3,449,293)
Ending Cumulative Balance	182	$ 77,011,426	$ (8,733,875)	$ 68,277,551

Comments:

(1) The Texas retail fixed fuel factor is 4.44500 cents/kWh effective with September 2010 billing cycles.

(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF OCTOBER 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,177,935	$ 2,401,672	$ 2.039	69,217	$ 34.698	8,509.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	16	253	15.813	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	2,744,417	7,077,771	2.579	160,044	44.224	8,573.9
SunCoast Products	Igniter Fuel	Firm		Nelson 6	10,531	176,906	16.799	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	(79,297)	132,525	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	(2,874)	(47,988)	-	-	-	-
				TOTAL COAL:	3,850,728	$ 9,741,139	$ 2.530	229,261	$ 42.489	8,398.1
CONOCO	NG	SPOT		Sabine	40,000	$ 138,652	$ 3.466			
DCP MIDSTREAM	NG	SPOT		Sabine	800,000	3,099,784	3.875			
ENBRIDGE	NG	SPOT		Sabine	2,422,807	9,217,810	3.805			
ETC MARKETING	NG	SPOT		Sabine	345,000	1,356,466	3.932			
JLA ENERGY	NG	SPOT		Sabine	585,000	2,095,477	3.582			
KMTEJAS	NG	SPOT		Sabine	130,000	451,434	3.473			
NJR	NG	SPOT		Sabine	10,000	35,670	3.567			
NOBLE	NG	SPOT		Sabine	2,691	10,110	3.757			
PACIFIC SUMMIT	NG	SPOT		Sabine	20,000	70,326	3.516			
SEQUENT	NG	SPOT		Sabine	300,000	1,048,767	3.496			
TAUBER	NG	SPOT		Sabine	20,000	69,726	3.486			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	(12,320)	109,871	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	4,663,178	$ 17,704,093	$ 3.797			
ENBRIDGE	NG	SPOT		Lewis Creek	680,000	$ 2,581,274	$ 3.796			
JLA ENERGY	NG	SPOT		Lewis Creek	10,000	36,700	3.670			
NJR	NG	SPOT		Lewis Creek	15,000	49,048	3.270			
PACIFIC SUMMIT	NG	SPOT		Lewis Creek	60,000	197,490	3.292			
SEQUENT	NG	SPOT		Lewis Creek	520,000	1,899,455	3.653			
SW ENERGY	NG	SPOT		Lewis Creek	100,000	348,175	3.482			
TAUBER	NG	SPOT		Lewis Creek	205,000	707,583	3.452			
TETCO	NG	SPOT		Lewis Creek	-	109,500	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek			-			
Prior Period Adjustments	NG	N/A		Lewis Creek	(44,469)	(162,952)	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	1,545,531	$ 5,766,272	$ 3.731			
		TOTAL NATURAL GAS & OIL			6,208,709	$ 23,470,365	$ 3.780			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF OCTOBER 2010

Time Period: 744 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
COAL/OIL:	Nelson 6	385.0	116,585	1,319,802	$ 3,476,734	40.70%	11.321	$ 2.634	$ 29.82	10.65%
	Big Cajun No. 2 Unit 3	227.0	19,734	168,598	299,553	11.68%	8.544	1.777	15.18	1 80%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	136,319	1,488,400	$ 3,776,287	29.94%	10.919	$ 2.537	$ 27.70	12.46%
GAS/OIL:	Lewis Creek	520.0	135,079	1,604,934	$ 5,989,845	34.91%	11.881	$ 3.732	$ 44.34	12.34%
	Sabine	1,890.0	423,942	5,037,470	19,063,708	30.15%	11.882	3.784	44.97	38 74%
	Prior Period Adjustments		-	(42,145)	(7,772)	-	-	-	-	0.00%
	TOTAL GAS/OIL	2,410.0	559,021	6,600,259	$ 25,045,781	31.18%	11.807	$ 3.795	$ 44.80	51.09%
EMISSIONS & GAINS	509 & 411	-	-	-	6,830	-	-	-	-	0 00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0 00%
	TOTAL EMISSIONS	-	-	-	$ 6,830	-	-	$ -	$ -	
	TOTAL NET GENERATION	3,022.0	695,340	8,088,659	$ 28,828,898	30.93%	11.633	$ 3.564	$ 41.46	63.54%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		286,861	N/A	9,320,683	N/A	N/A	N/A	32.49	26.21%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		286,861		$ 9,320,683				$ 32 49	26.21%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		112,086	N/A	(10,184,913)	N/A	N/A	N/A	(90.87)	10.24%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		112,086		$ (10,184,913)				$ (90.87)	10.24%
	TOTAL PURCHASES		398,947		$ (864,230)				$ (2.17)	36.46%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,094,287		$ 27,964,668				$ 25.56	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,372,041							125.38%
	Sales for Resale		98,028							8.96%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0 00%
	Electric Dept. Only		1,647							0.15%
	TOTAL @ THE METER		1,471,716							134.49%
	Total Energy Losses *		(377,429)							-34.49%
	Percent Losses *									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	(161)	(1,377)	$ (25,678)	N/A	-	$ 18.648	$ 159 49	-0.02%
	Nelson 6	385.0	181	2,054	32,039	N/A	11.350	15.595	177.01	0.02%
	Sabine	1,890.0	1	13	207	N/A	13.280	15 587	207.00	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		21	691	$ 6,568		32.890	$ 9.509	$ 312.76	0.00%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

(2) Other Non-Firm Purchases are net of off-system sales 334,398 mWh
$ 14,087,091

Control Number: 37856

Item Number: 128

Addendum StartPage: 0

PROJECT NO. 37856

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ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF NOVEMBER 2010

Current System Fuel Factor: (1)

TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
Fuel Cost	501	$ 20,658,119	$ 132,880	$ 20,790,999
Allowances	509	$ 5,503	$ -	$ 5,503
Purchased Power Cost - Nuclear	555	1,545,716	10,885,139	12,430,855
Purchased Power Cost - Non-Nuclear	555	23,566,085	8,899,342	32,465,427
TOTAL SYSTEM COST:		$ 45,775,423	$ 19,917,361	$ 65,692,784
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	11,627,955	3,912,871	15,540,826
NET SYSTEM COST:		$ 34,147,468	$ 16,004,490	$ 50,151,958
Texas Fixed Fuel Factor Allocator		91.885%	91.885%	91.885%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 31,376,401	$ 14,705,726	$ 46,082,127

TEXAS FIXED FUEL FACTOR RELATED REVENUES:	ACCOUNT	REVENUES	MWH SALES
Residential	440	$ 17,206,546	374,152
Commercial & Industrial	442	34,050,547	770,157
Street & Highway	444	305,682	6,647
Public Authorities	445	930,064	20,514
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 52,492,839	1,171,470

OVER/(UNDER) RECOVERY OF COSTS:	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
Annual Interest Compound Rate (%):			0.61%	
Beginning Cumulative Balance	182	77,011,426	(8,733,875)	68,277,551
Entry This Month	182	21,116,438	34,611	21,151,049
Docket No. 38403 Refund	182	(15,234,524)	(100,845)	(15,335,369)
For Future Use	182	-		-
Ending Cumulative Balance	182	$ 82,893,340	$ (8,800,109)	$ 74,093,231

Comments:

(1) The Texas retail fixed fuel factor is 4.44500 cents/kWh effective with September 2010 billing cycles.
(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF NOVEMBER 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,620,970	$ 1,878,629	$ 1.159	95,441	$ 19.684	8,492.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	1,300	22,472	17.286	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	2,964,591	7,758,030	2.617	171,291	45.292	8,653.7
SunCoast Products	Igniter Fuel	Firm		Nelson 6	2	40	20.000	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	-	129,986	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	1,284	22,219	-	-	-	-
				TOTAL COAL:	4,588,147	$ 9,811,376	$ 2.138	266,732	$ 36.784	8,600.7
CONOCO	NG	SPOT		Sabine	65,000	$ 237,369	$ 3.652			
DCP MIDSTREAM	NG	SPOT		Sabine	900,000	3,052,311	3.391			
ENBRIDGE	NG	SPOT		Sabine	2,067,000	7,084,220	3.427			
ETC MARKETING	NG	SPOT		Sabine	310,000	1,056,252	3.407			
JLA ENERGY	NG	SPOT		Sabine	60,000	205,587	3.426			
PACIFIC SUMMIT	NG	SPOT		Sabine	30,000	105,110	3.504			
SEQUENT	NG	SPOT		Sabine	200,000	745,831	3.729			
TAUBER	NG	SPOT		Sabine	250,000	948,314	3.793			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	(14,396)	(63,423)	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	3,867,604	$ 13,371,572	$ 3.457			
BGEM	NG	SPOT		Lewis Creek	358,500	$ 1,309,598	$ 3.653			
ENBRIDGE	NG	SPOT		Lewis Creek	490,000	1,728,797	3.528			
SEQUENT	NG	SPOT		Lewis Creek	220,000	671,505	3.052			
SW ENERGY	NG	SPOT		Lewis Creek	40,000	135,400	3.385			
TAUBER	NG	SPOT		Lewis Creek	15,000	49,698	3.313			
TETCO	NG	SPOT		Lewis Creek	-	109,500	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek			-			
Prior Period Adjustments	NG	N/A		Lewis Creek	(33,773)	(125,435)	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	1,089,727	$ 3,879,062	$ 3.560			
				TOTAL NATURAL GAS & OIL	4,957,331	$ 17,250,634	$ 3.480			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF NOVEMBER 2010

Time Period: 720 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
COAL/OIL:	Nelson 6	385.0	117,322	1,290,563	$ 3,368,064	42.32%	11.000	$ 2.610	$ 28.71	9.25%
	Big Cajun No. 2 Unit 3	227.0	74,732	767,782	1,374,308	45.72%	10.274	1.790	18.39	5.89%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	192,054	2,058,345	$ 4,742,372	43.59%	10.718	$ 2.304	$ 24.69	15.14%
GAS/OIL:	Lewis Creek	520.0	93,583	1,123,500	$ 4,004,497	25.00%	12.005	$ 3.564	$ 42.79	7.38%
	Sabine	1,890.0	329,275	3,753,743	13,009,339	24.20%	11.400	3.466	39.51	25.96%
	Prior Period Adjustments		-	(272,120)	(1,098,089)	-	-	-	-	0.00%
	TOTAL GAS/OIL	2,410.0	422,858	4,605,123	$ 15,915,747	24.37%	10.890	$ 3.456	$ 37.64	33.33%
EMISSIONS & GAINS	509 & 411	-	-	-	5,503	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 5,503	-	-	$ -	$ -	
	TOTAL NET GENERATION	3,022.0	614,912	6,663,468	$ 20,663,622	28.26%	10.836	$ 3.101	$ 33.60	48.47%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		378,268	N/A	12,128,444	N/A	N/A	N/A	32.06	29.82%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		378,268		$ 12,128,444				$ 32.06	29.82%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		275,425	N/A	1,355,402	N/A	N/A	N/A	4.92	21.71%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		275,425		$ 1,355,402				$ 4.92	21.71%
	TOTAL PURCHASES		653,693		$ 13,483,846				$ 20.63	51.53%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,268,605		$ 34,147,468				$ 26.92	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,216,625							95.90%
	Sales for Resale		65,941							5.20%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,511							0.12%
	TOTAL @ THE METER		1,284,077							101.22%
	Total Energy Losses *		(15,472)							-1.22%
	Percent Losses *									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	367	3,769	$ 69,152	N/A	10.269	$ 18.350	$ 188.43	0.03%
	Nelson 6	385.0	42	458	7,138	N/A	10.898	15.595	169.95	0.00%
	Sabine	1,890.0	1	7	105	N/A	6.730	15.602	105.00	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		410	4,233	$ 76,395		10.324	$ 18.047	$ 186.33	0.03%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

(2) Other Non-Firm Purchases are net of off-system sales· 259,988 mWh
$ 11,627,955

Control Number: 37856

Item Number: 139

Addendum StartPage: 0

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF DECEMBER 2010

Current System Fuel Factor: (1)

	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:				
Fuel Cost	501	$ 27,232,114	$ 116,517	$ 27,348,631
Allowances	509	$ 6,920	$ -	$ 6,920
Purchased Power Cost - Nuclear	555	1,681,284	6,554,944	8,236,228
Purchased Power Cost - Non-Nuclear	555	33,597,869	12,050,538	45,648,407
TOTAL SYSTEM COST:		$ 62,518,187	$ 18,721,999	$ 81,240,186
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	13,252,958	4,223,305	17,476,263
NET SYSTEM COST:		$ 49,265,229	$ 14,498,694	$ 63,763,923
Texas Fixed Fuel Factor Allocator		92.961%	92.961%	92.961%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 45,797,449	$ 13,478,131	$ 59,275,580

	ACCOUNT	REVENUES	MWH SALES
TEXAS FIXED FUEL FACTOR RELATED REVENUES:			
Residential	440	$ 18,011,024	391,645
Commercial & Industrial	442	33,051,485	748,294
Street & Highway	444	308,090	6,699
Public Authorities	445	841,261	18,578
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 52,211,860	1,165,216

	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
OVER/(UNDER) RECOVERY OF COSTS:				
		Annual Interest Compound Rate (%):	0.61%	
Beginning Cumulative Balance	182	82,893,340	(8,800,109)	74,093,231
Entry This Month	182	6,414,411	37,559	6,451,970
Docket No. 38403 Refund	182	(40,022)	(265)	(40,287)
True-up adjustments from closed dockets	182	(1,655,770)	(133,182)	(1,788,952)
Docket No. 37744 IPCR Balance	182	(344,016)	105,622	(238,394)
Ending Cumulative Balance	182	$ 87,267,943	$ (8,790,375)	$ 78,477,568

Comments:
(1) The Texas retail fixed fuel factor is 4.44500 cents/kWh effective with September 2010 billing cycles.
(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF DECEMBER 2010

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,393,203	$ 2,806,089	$ 2.014	82,840	$ 33.874	8,409.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	615	11,358	18.468	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	3,140,401	8,265,797	2.632	183,668	45.004	8,549.1
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	6,749	137,243	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	(685)	(11,114)	-	-	-	-
				TOTAL COAL:	4,540,283	$ 11,209,373	$ 2.469	266,508	$ 42.060	8,518.1
DCP MIDSTREAM	NG	SPOT		Sabine	1,050,000	$ 4,575,430	$ 4.358			
ENBRIDGE	NG	SPOT		Sabine	2,224,000	9,641,632	4.335			
KMTEJAS	NG	SPOT		Sabine	620,000	2,721,965	4.390			
TAUBER	NG	SPOT		Sabine	10,000	46,575	4.657			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	(259)	91,597	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	3,903,741	$ 17,077,199	$ 4.375			
ENBRIDGE	NG	SPOT		Lewis Creek	745,000	$ 3,226,052	$ 4.330			
KMTEJAS	NG	SPOT		Lewis Creek	30,000	137,400	4.580			
SEQUENT	NG	SPOT		Lewis Creek	355,000	1,494,235	4.209			
SW ENERGY	NG	SPOT		Lewis Creek	50,000	205,250	4.105			
TAUBER	NG	SPOT		Lewis Creek	315,000	1,315,400	4.176			
TETCO	NG	SPOT		Lewis Creek	-	109,500	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek			-			
Prior Period Adjustments	NG	N/A		Lewis Creek	15,163	64,837	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	1,510,163	$ 6,552,673	$ 4.339			
				TOTAL NATURAL GAS & OIL	5,413,904	$ 23,629,872	$ 4.365			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 37856

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF DECEMBER 2010

Time Period: 744 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
COAL/OIL:	Nelson 6	385.0	90,475	950,528	$ 2,505,223	31.59%	10.506	$ 2.636	$ 27.69	6.31%
	Big Cajun No. 2 Unit 3	227.0	75,747	772,050	1,337,456	44.85%	10.192	1.732	17.66	5.28%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	166,222	1,722,579	$ 3,842,679	36.51%	10.363	$ 2.231	$ 23.12	11.59%
GAS/OIL:	Lewis Creek	520.0	117,644	1,495,000	$ 6,487,836	30.41%	12.708	$ 4.340	$ 55.15	8.21%
	Sabine	1,890.0	330,148	3,834,448	16,700,787	23.48%	11.614	4.355	50.59	23.03%
	Prior Period Adjustments		-	29,048	200,812	-	-	-	-	0.00%
	TOTAL GAS/OIL	2,410.0	447,792	5,358,496	$ 23,389,435	24.97%	11.966	$ 4.365	$ 52.23	31.23%
EMISSIONS & GAINS	509 & 411	-	-	-	6,920	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 6,920	-	-	$ -	$ -	
	TOTAL NET GENERATION	3,022.0	614,014	7,081,075	$ 27,239,034	27.31%	11.532	$ 3.847	$ 44.36	42.83%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		430,552	N/A	16,773,614	N/A	N/A	N/A	38.96	30.03%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		430,552		$ 16,773,614				$ 38.96	30.03%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		389,178	N/A	5,252,581	N/A	N/A	N/A	13.50	27.14%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		389,178		$ 5,252,581				$ 13.50	27.14%
	TOTAL PURCHASES		819,730		$ 22,026,195				$ 26.87	57.17%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,433,744		$ 49,265,229				$ 34.36	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,214,591							84.71%
	Sales for Resale		46,368							3.23%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,636							0.11%
	TOTAL @ THE METER		1,262,595							88.05%
	Total Energy Losses *		171,149							11.95%
	Percent Losses *									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	(155)	(1,580)	$ (29,571)	N/A	-	$ 18.715	$ 190.78	-0.01%
	Nelson 6	385.0	369	3,876	60,451	N/A	10.505	15.595	163.82	0.03%
	Sabine	1,890.0	-	2	27	N/A	-	15.789	#DIV/0!	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		214	2,298	$ 30,907		10.738	$ 13.450	$ 144.43	0.02%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

(2) Other Non-Firm Purchases are net of off-system sales: 271,458 mWh
$ 13,252,958

Control Number: 39036

Item Number: 27

Addendum StartPage: 0

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF JANUARY 2011

Current System Fuel Factor: (1)

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TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
Fuel Cost	501	$ 27,922,361	$ 101,488	$ 28,023,849
Allowances	509	$ 2,606	$ -	$ 2,606
Purchased Power Cost - Nuclear	555	866,444	11,924,531	12,790,975
Purchased Power Cost - Non-Nuclear	555	42,103,715	10,416,967	52,520,682
TOTAL SYSTEM COST:		$ 70,895,126	$ 22,442,986	$ 93,338,112
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	14,662,388	5,849,884	20,512,272
NET SYSTEM COST:		$ 56,232,738	$ 16,593,102	$ 72,825,840
Texas Fixed Fuel Factor Allocator		92.274%	92.274%	92.274%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 51,888,196	$ 15,311,119	$ 67,199,315

TEXAS FIXED FUEL FACTOR RELATED REVENUES:	ACCOUNT	REVENUES	MWH SALES
Residential	440	$ 23,095,117	502,198
Commercial & Industrial	442	36,097,940	817,935
Street & Highway	444	311,804	6,780
Public Authorities	445	939,142	20,745
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 60,444,003	1,347,658

OVER/(UNDER) RECOVERY OF COSTS:	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
	Annual Interest Compound Rate (%):		0.28%	
Beginning Cumulative Balance	182	87,267,943	(8,790,375)	78,477,568
Entry This Month	182	8,555,807	18,288	8,574,095
	182			-
	182			-
	182			-
Ending Cumulative Balance	182	$ 95,823,750	$ (8,772,087)	$ 87,051,663

Comments:
(1) The Texas retail fixed fuel factor is 4.44500 cents/kWh effective with September 2010 billing cycles.
(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

1

27

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF JANUARY 2011

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,550,247	$ 3,051,885	$ 1.969	91,363	$ 33.404	8,484.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	10	164	16.400	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	3,366,374	9,140,073	2.715	193,709	47.185	8,689.3
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	6,749	132,470	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	(605)	(11,195)	-	-	-	-
				TOTAL COAL:	4,922,775	$ 12,313,397	$ 2.501	285,072	$ 43.194	8,634.3
CITIGROUP	NG	SPOT		Sabine	10,000	$ 45,358	$ 4.536			
CONOCO	NG	SPOT		Sabine	10,000	45,308	4.531			
DCP MIDSTREAM	NG	SPOT		Sabine	1,140,000	4,914,589	4.311			
ENBRIDGE	NG	SPOT		Sabine	2,442,815	10,258,382	4.199			
ETC MARKETING	NG	SPOT		Sabine	45,000	202,888	4.509			
JP MORGAN VNTRS	NG	SPOT		Sabine	10,000	45,858	4.586			
KMTEJAS	NG	SPOT		Sabine	170,000	748,867	4.405			
SEQUENT	NG	SPOT		Sabine	20,000	91,217	4.561			
STORAGE	NG	SPOT		Sabine	(7,500)	(32,502)	4.334			
TAUBER	NG	SPOT		Sabine	30,000	125,875	4.196			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	17,986	(244,930)	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	3,888,301	$ 16,200,911	$ 4.167			
BGEM	NG	SPOT		Lewis Creek	130,000	$ 572,750	$ 4.406			
CONOCO	NG	SPOT		Lewis Creek	25,000	110,188	4.408			
ENBRIDGE	NG	SPOT		Lewis Creek	795,000	3,452,574	4.343			
ONEOK EM&T	NG	SPOT		Lewis Creek	100,000	454,054	4.541			
SEQUENT	NG	SPOT		Lewis Creek	490,000	2,088,910	4.263			
STORAGE	NG	SPOT		Lewis Creek	7,500	32,438	-			
SW ENERGY	NG	SPOT		Lewis Creek	85,000	383,050	4.506			
TAUBER	NG	SPOT		Lewis Creek	50,000	221,429	-			
TETCO	NG	SPOT		Lewis Creek	-	109,500	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek			-			
Prior Period Adjustments	NG	N/A		Lewis Creek	(50,999)	(218,193)	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	1,631,501	$ 7,206,699	$ 4.417			
		TOTAL NATURAL GAS & OIL			5,519,802	$ 23,407,610	$ 4.241			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF JANUARY 2011

Time Period: 744 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
COAL/OIL:	Nelson 6	385.0	116,053	1,219,749	$ 3,216,986	40.52%	10.510	$ 2.637	$ 27.72	7.65%
	Big Cajun No. 2 Unit 3	227.0	76,860	790,779	1,434,777	45.51%	10.289	1.814	18.67	5.07%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	192,913	2,010,529	$ 4,651,763	42.37%	10.422	$ 2.314	$ 24.11	12.72%
GAS/OIL:	Lewis Creek	520.0	138,896	1,682,500	$ 7,424,892	35.90%	12.113	$ 4.413	$ 53.46	9.16%
	Sabine	1,890.0	331,810	3,828,411	16,272,600	23.60%	11.538	4.250	49.04	21.87%
	Prior Period Adjustments		-	(25,615)	(426,894)	-	-	-	-	0.00%
	TOTAL GAS/OIL	2,410.0	470,706	5,485,296	$ 23,270,598	26.25%	11.653	$ 4.242	$ 49.44	31.03%
EMISSIONS & GAINS	509 & 411	-	-	-	2,606	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 2,606	-	-	$ -	$ -	
	TOTAL NET GENERATION	3,022.0	663,619	7,495,825	$ 27,924,967	29.52%	11.295	$ 3.725	$ 42.08	43.75%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		458,269	N/A	18,160,193	N/A	N/A	N/A	39.63	30.21%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		458,269		$ 18,160,193				$ 39.63	30.21%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		395,039	N/A	10,147,578	N/A	N/A	N/A	25.69	26.04%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		395,039		$ 10,147,578				$ 25.69	26.04%
	TOTAL PURCHASES		853,308		$ 28,307,771				$ 33.17	56.25%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,516,927		$ 56,232,738				$ 37.07	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,366,623							90.09%
	Sales for Resale		102,620							6.76%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,785							0.12%
	TOTAL @ THE METER		1,471,028							96.97%
	Total Energy Losses *		45,899							3.03%
	Percent Losses *									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	99	1,017	$ 18,968	N/A	10.268	$ 18.659	$ 191.60	0.01%
	Nelson 6	385.0	19	201	3,138	N/A	10.589	15.597	165 16	0.00%
	Sabine	1,890.0	-	(2)	(34)	N/A	-	15.596	#DIV/0!	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		118	1,216	$ 22,072		10.301	$ 18.158	$ 187.05	0.01%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month

(2) Other Non-Firm Purchases are net of off-system sales: 287,719 mWh
$ 14,662,388

Control Number: 39036

Item Number: 19

Addendum StartPage: 0

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF FEBRUARY 2011

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Current System Fuel Factor: (1)

TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
Fuel Cost	501	$ 24,226,143	$ 169,565	$ 24,395,708
Allowances	509	$ 1,428	$ -	$ 1,428
Purchased Power Cost - Nuclear	555	1,015,154	8,811,728	9,826,882
Purchased Power Cost - Non-Nuclear	555	41,306,171	8,990,303	50,296,474
TOTAL SYSTEM COST:		$ 66,548,896	$ 17,971,596	$ 84,520,492
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	14,087,589	4,022,505	18,110,094
NET SYSTEM COST:		$ 52,461,307	$ 13,949,091	$ 66,410,398
Texas Fixed Fuel Factor Allocator		92.773%	92.773%	92.773%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 48,669,929	$ 12,940,990	$ 61,610,919

TEXAS FIXED FUEL FACTOR RELATED REVENUES:	ACCOUNT	REVENUES	MWH SALES
Residential	440	$ 23,771,936	516,915
Commercial & Industrial	442	35,681,991	809,195
Street & Highway	444	311,432	6,772
Public Authorities	445	883,658	19,493
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 60,649,017	1,352,375

OVER/(UNDER) RECOVERY OF COSTS:	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
		Annual Interest Compound Rate (%):	0.28%	
Beginning Cumulative Balance	182	95,823,750	(8,772,087)	87,051,663
Entry This Month	182	11,979,088	20,286	11,999,374
Docket No. 38967 Refund	182	(41,446,933)	(1,133,233)	(42,580,166)
Billing Adjustment	182	(523,768)		(523,768)
	182			-
Ending Cumulative Balance	182	$ 65,832,137	$ (9,885,034)	$ 55,947,103

Comments:

(1) The Texas retail fixed fuel factor is 4.44500 cents/kWh effective with September 2010 billing cycles.

(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF FEBRUARY 2011

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,594,466	$ 3,408,576	$ 2.138	93,969	$ 36.273	8,484.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	725	14,810	20.428	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	2,099,334	5,751,096	2.739	120,947	47.551	8,678.7
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	6,749	125,217	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	715	14,646	-	-	-	-
				TOTAL COAL:	3,701,989	$ 9,314,345	$ 2.516	214,916	$ 43.339	8,612.6
CONOCO	NG	SPOT		Sabine	5,800	$ 28,599	$ 4.931			
DCP MIDSTREAM	NG	SPOT		Sabine	740,000	3,382,492	4.571			
ENBRIDGE	NG	SPOT		Sabine	1,803,696	7,897,016	4.378			
JLA ENERGY	NG	SPOT		Sabine	40,000	196,521	4.913			
JP MORGAN VNTRS	NG	SPOT		Sabine	260,000	1,153,443	4.436			
KMTEJAS	NG	SPOT		Sabine	30,000	151,141	5.038			
NJR	NG	SPOT		Sabine	100,000	475,308	4.753			
SEQUENT	NG	SPOT		Sabine	130,000	603,214	4.640			
STORAGE	NG	SPOT		Sabine	(1,215)	(5,817)	4.788			
	NG	SPOT		Sabine			-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	9,834	255,059	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	3,118,115	$ 14,136,976	$ 4.534			
BGEM	NG	SPOT		Lewis Creek	420,000	$ 1,780,800	$ 4.240			
CONOCO	NG	SPOT		Lewis Creek	40,000	188,568	4.714			
ENBRIDGE	NG	SPOT		Lewis Creek	660,000	2,902,213	4.397			
JP MORGAN VNTRS	NG	SPOT		Lewis Creek	25,000	104,088	4.164			
ONEOK EM&T	NG	SPOT		Lewis Creek	16,000	76,830	4.802			
SEQUENT	NG	SPOT		Lewis Creek	175,000	763,754	4.364			
STORAGE	NG	SPOT		Lewis Creek	1,215	5,741	4.725			
SW ENERGY	NG	SPOT		Lewis Creek	50,000	208,700	4.174			
TAUBER	NG	SPOT		Lewis Creek	45,000	206,218	4.583			
TETCO	NG	SPOT		Lewis Creek	-	109,500				
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek			-			
Prior Period Adjustments	NG	N/A		Lewis Creek	(63,041)	(271,567)	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	1,369,174	$ 6,074,843	$ 4.437			
				TOTAL NATURAL GAS & OIL	4,487,289	$ 20,211,820	$ 4.504			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF FEBRUARY 2011

Time Period: 672 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
COAL/OIL:	Nelson 6	385.0	107,872	1,171,011	$ 3,139,165	41.69%	10.856	$ 2.681	$ 29.10	7.66%
	Big Cajun No. 2 Unit 3	227.0	59,178	610,172	1,150,477	38.79%	10.311	1.885	19.44	4.20%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	167,050	1,781,183	$ 4,289,642	40.62%	10.663	$ 2.408	$ 25.68	11.85%
GAS/OIL:	Lewis Creek	520.0	133,991	1,432,215	$ 6,346,410	38.34%	10.689	$ 4.431	$ 47.36	9.51%
	Sabine	1,890.0	268,845	3,028,571	13,561,039	21.17%	11.265	4.478	50.44	19.08%
	Prior Period Adjustments		-	(41,788)	29,051	-	-	-	-	0.00%
	TOTAL GAS/OIL	2,410.0	402,836	4,418,998	$ 19,936,500	24.87%	10.970	$ 4.512	$ 49.49	28.59%
EMISSIONS & GAINS	509 & 411	-	-	-	1,428	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 1,428	-	-	$ -	$ -	
	TOTAL NET GENERATION	3,022.0	569,886	6,200,181	$ 24,227,570	28.06%	10.880	$ 3.908	$ 42.51	40.44%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		335,678	N/A	12,578,999	N/A	N/A	N/A	37.47	23.82%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		335,678		$ 12,578,999				$ 37.47	23.82%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		503,620	N/A	15,654,738	N/A	N/A	N/A	31.08	35.74%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		503,620		$ 15,654,738				$ 31.08	35.74%
	TOTAL PURCHASES		839,298		$ 28,233,737				$ 33.64	59.56%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,409,184		$ 52,461,307				$ 37.23	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,362,742							96.70%
	Sales for Resale		103,711							7.36%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,613							0.11%
	TOTAL @ THE METER		1,468,066							104.17%
	Total Energy Losses *		(58,882)							-4.17%
	Percent Losses *									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	61	634	$ 12,204	N/A	10.389	$ 19.258	$ 200.07	0.00%
	Nelson 6	385.0	203	2,203	34,484	N/A	10.850	15.656	169.87	0.01%
	Sabine	1,890.0	1	14	223	N/A	14.220	15.682	223.00	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		265	2,851	$ 46,911		10.757	$ 16.457	$ 177.02	0.02%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

(2) Other Non-Firm Purchases are net of off-system sales: 251,836 mWh
$ 14,087,589

Control Number: 39036

Item Number: 35

Addendum StartPage: 0

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF MARCH 2011

Current System Fuel Factor: (1)

TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
Fuel Cost	501	$ 27,587,427	$ 34,178	$ 27,621,605
Allowances	509	$ 1,428	$ -	$ 1,428
Purchased Power Cost - Nuclear	555	1,946,811	9,306,473	11,253,284
Purchased Power Cost - Non-Nuclear	555	33,220,182	10,755,316	43,975,498
TOTAL SYSTEM COST:		$ 62,755,848	$ 20,095,967	$ 82,851,815
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	12,017,734	5,390,861	17,408,595
NET SYSTEM COST:		$ 50,738,114	$ 14,705,106	$ 65,443,220
Texas Fixed Fuel Factor Allocator		90.379%	90.379%	90.379%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 45,856,600	$ 13,290,328	$ 59,146,928

TEXAS FIXED FUEL FACTOR RELATED REVENUES:	ACCOUNT	REVENUES	MWH SALES
Residential	440	$ 15,034,198	360,573
Commercial & Industrial	442	29,649,948	741,254
Street & Highway	444	281,864	6,760
Public Authorities	445	759,702	18,501
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 45,725,712	1,127,088

OVER/(UNDER) RECOVERY OF COSTS:	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
Annual Interest Compound Rate (%):			0.28%	
Beginning Cumulative Balance	182	65,832,137	(9,885,034)	55,947,103
Entry This Month	182	(130,888)	13,038	(117,850)
Docket No. 38967 Refund	182	(14,915,665)	(407,821)	(15,323,486)
RPCEA refund	182	1,166,792	544	1,167,336
	182			-
Ending Cumulative Balance	182	$ 51,952,376	$ (10,279,273)	$ 41,673,103

Comments:

(1) The Texas retail fixed fuel factor is 4.03008 cents/kWh effective with March 2011 billing cycles.

(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

35

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF MARCH 2011

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,894,803	$ 3,613,644	$ 1.907	111,459	$ 32.421	8,500.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	767	15,822	20.628	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	727,130	2,015,392	2.772	40,987	49.171	8,870.3
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	6,749	132,778	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	42	1,012	-	-	-	-
				TOTAL COAL:	2,629,491	$ 5,778,648	$ 2.198	152,446	$ 37.906	8,624.3
CITIGROUP	NG	SPOT		Sabine	15,000	$ 63,359	$ 4.224			
CONOCO	NG	SPOT		Sabine	30,000	122,012	4.067			
DCP MIDSTREAM	NG	SPOT		Sabine	1,070,000	4,226,135	3.950			
ENBRIDGE	NG	SPOT		Sabine	2,467,666	9,771,954	3.960			
ETC MARKETING	NG	SPOT		Sabine	220,000	941,133	4.278			
JLA ENERGY	NG	SPOT		Sabine	60,000	260,664	4.344			
JP MORGAN VNTRS	NG	SPOT		Sabine	180,000	746,590	4.148			
KMTEJAS	NG	SPOT		Sabine	140,000	596,999	4.264			
SEQUENT	NG	SPOT		Sabine	210,000	883,941	4.209			
	NG	SPOT		Sabine			-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	22,139	407,942	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	4,414,805	$ 18,020,729	$ 4.082			
BGEM	NG	SPOT		Lewis Creek	155,000	$ 587,450	$ 3.790			
ENBRIDGE	NG	SPOT		Lewis Creek	600,000	2,356,166	3.927			
JP MORGAN VNTRS	NG	SPOT		Lewis Creek	140,000	529,835	3.785			
SEQUENT	NG	SPOT		Lewis Creek	395,000	1,493,168	3.780			
SW ENERGY	NG	SPOT		Lewis Creek	178,000	719,595	4.043			
TAUBER	NG	SPOT		Lewis Creek	70,000	265,005	3.786			
TETCO	NG	SPOT		Lewis Creek	-	109,500				
	NG	SPOT		Lewis Creek			-			
	NG	SPOT		Lewis Creek			-			
	NG	SPOT		Lewis Creek						
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek			-			
Prior Period Adjustments	NG	N/A		Lewis Creek	105,032	475,272	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	1,643,032	$ 6,535,991	$ 3.978			
				TOTAL NATURAL GAS & OIL	6,057,837	$ 24,556,720	$ 4.054			

Comments. (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF MARCH 2011

Time Period: 744 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
COAL/OIL:	Nelson 6	385.0	8,508	77,606	$ 212,716	2.97%	9.122	$ 2.741	$ 25.00	0.62%
	Big Cajun No. 2 Unit 3	227.0	74,106	786,284	1,488,970	43.88%	10.610	1.894	20.09	5.42%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	82,615	863,890	$ 1,701,686	18.14%	10.457	$ 1.970	$ 20.60	6.04%
GAS/OIL:	Lewis Creek	520.0	140,657	1,538,000	$ 6,060,719	36.36%	10.934	$ 3.941	$ 43.09	10.28%
	Sabine	1,890.0	373,021	4,617,436	18,523,690	26.53%	12.378	4.012	49.66	27.27%
	Prior Period Adjustments		-	230,364	1,301,332	-	-	-	-	0.00%
	TOTAL GAS/OIL	2,410.0	513,678	6,385,800	$ 25,885,741	28.65%	12.432	$ 4.054	$ 50.39	37.55%
EMISSIONS	509 & 411	-	-	-	1,428	-	-	-	-	0.00%
& GAINS		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 1,428	-	-	$ -	$ -	
	TOTAL NET GENERATION	3,022.0	596,293	7,249,690	$ 27,588,855	26.52%	12.158	$ 3.806	$ 46.27	43.59%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		399,331	N/A	14,535,713	N/A	N/A	N/A	36.40	29.19%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		399,331		$ 14,535,713				$ 36.40	29.19%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		372,410	N/A	8,613,546	N/A	N/A	N/A	23.13	27.22%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		372,410		$ 8,613,546				$ 23.13	27.22%
	TOTAL PURCHASES		771,741		$ 23,149,259				$ 30.00	56.41%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,368,034		$ 50,738,114				$ 37.09	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,161,253							84.88%
	Sales for Resale	-	93,282							6.82%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,451							0.11%
	TOTAL @ THE METER		1,255,986							91.81%
	Total Energy Losses		112,048							8.19%
	Percent Losses									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	137	1,454	$ 28,456	N/A	10.612	$ 19.572	$ 207.71	0.01%
	Nelson 6	385.0	49	449	7,036	N/A	9.173	15.654	143.59	0.00%
	Sabine	1,890.0	2	21	323	N/A	10.325	15.642	161.50	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		188	1,924	$ 35,815		10.234	$ 18.615	$ 190.51	0.01%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

(2) Other Non-Firm Purchases are net of off-system sales: 309,113 mWh
$ 12,017,734

Control Number: 39036

Item Number: 46

Addendum StartPage: 0

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF APRIL 2011

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Current System Fuel Factor: (1)

TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
Fuel Cost	501	$ 26,571,231	$ 134,656	$ 26,705,887
Allowances	509	$ 1,849	$ -	$ 1,849
Purchased Power Cost - Nuclear	555	1,794,874	9,777,399	11,572,273
Purchased Power Cost - Non-Nuclear	555	39,287,095	9,964,544	49,251,639
TOTAL SYSTEM COST:		$ 67,655,049	$ 19,876,599	$ 87,531,648
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	19,945,278	5,281,526	25,226,804
NET SYSTEM COST:		$ 47,709,771	$ 14,595,073	$ 62,304,844
Texas Fixed Fuel Factor Allocator		89.021%	89.021%	89.021%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 42,471,715	$ 12,992,680	$ 55,464,395

TEXAS FIXED FUEL FACTOR RELATED REVENUES:	ACCOUNT	REVENUES	MWH SALES
Residential	440	$ 14,343,279	344,007
Commercial & Industrial	442	32,310,722	808,886
Street & Highway	444	282,616	6,778
Public Authorities	445	800,879	19,492
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 47,737,496	1,179,163

OVER/(UNDER) RECOVERY OF COSTS:	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
Annual Interest Compound Rate (%):			0.28%	
Beginning Cumulative Balance	182	51,952,376	(10,279,273)	41,673,103
Entry This Month	182	5,265,781	9,711	5,275,492
Docket No. 38967 Refund	182	(15,087,846)	(412,529)	(15,500,375)
	182			-
	182			-
Ending Cumulative Balance	182	$ 42,130,311	$ (10,682,091)	$ 31,448,220

Comments:

(1) The Texas retail fixed fuel factor is 4.03008 cents/kWh effective with March 2011 billing cycles.
(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF APRIL 2011

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,984,598	$ 4,562,407	$ 2.299	117,293	$ 38.898	8,460.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	922	21,790	23.633	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	884,338	2,578,809	2.916	50,908	50.656	8,685.6
SunCoast Products	Igniter Fuel	Firm		Nelson 6	10,828	239,904	22.156	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	6,749	149,900	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	155	5,968	-	-	-	-
				TOTAL COAL:	2,887,590	$ 7,558,778	$ 2.618	168,201	$ 44.939	8,583.7
CITIGROUP	NG	SPOT		Sabine	40,000	$ 171,060	$ 4.276			
DCP MIDSTREAM	NG	SPOT		Sabine	1,220,000	5,363,170	4.396			
ENBRIDGE	NG	SPOT		Sabine	2,269,318	9,876,656	4.352			
ETC MARKETING	NG	SPOT		Sabine	20,000	84,973	4.249			
JP MORGAN VNTRS	NG	SPOT		Sabine	140,000	585,396	4.181			
KMTEJAS	NG	SPOT		Sabine	600,000	2,657,198	4.429			
ONEOK EM&T	NG	SPOT		Sabine	10,000	42,387	4.239			
SEQUENT	NG	SPOT		Sabine	150,000	638,380	4.256			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	1,143	302,914	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	4,450,461	$ 19,722,133	$ 4.431			
BGEM	NG	SPOT		Lewis Creek	420,000	$ 1,769,000	$ 4.212			
ENBRIDGE	NG	SPOT		Lewis Creek	430,000	1,898,000	4.414			
JP MORGAN VNTRS	NG	SPOT		Lewis Creek	40,000	165,810	4.145			
SEQUENT	NG	SPOT		Lewis Creek	190,000	807,026	4.248			
SW ENERGY	NG	SPOT		Lewis Creek	10,000	40,800	4.080			
TETCO	NG	SPOT		Lewis Creek	-	109,500				
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek	-	-	-			
Prior Period Adjustments	NG	N/A		Lewis Creek	(6,810)	(21,004)	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	1,083,190	$ 4,769,132	$ 4.403			
		TOTAL NATURAL GAS & OIL			5,533,651	$ 24,491,265	$ 4.426			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF APRIL 2011

Time Period: 720 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
COAL/OIL:	Nelson 6	385.0	61,012	648,684	$ 1,835,990	22.01%	10.632	$ 2.830	$ 30.09	4.25%
	Big Cajun No. 2 Unit 3	227.0	58,429	595,363	1,181,676	35.75%	10.190	1.985	20.22	4.07%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	119,441	1,244,047	$ 3,017,666	27.11%	10.416	$ 2.426	$ 25.26	8.31%
GAS/OIL:	Lewis Creek	520.0	92,592	1,090,000	$ 4,790,136	24.73%	11.772	$ 4.395	$ 51.73	6.44%
	Sabine	1,890.0	429,577	4,633,525	20,165,328	31.57%	10.786	4.352	46.94	29.89%
	Prior Period Adjustments		-	(427,270)	(1,401,899)	-	-	-	-	0.00%
	TOTAL GAS/OIL	2,410.0	522,169	5,296,255	$ 23,553,565	30.09%	10.143	$ 4.447	$ 45.11	36.33%
EMISSIONS & GAINS	509 & 411	-	-	-	1,849	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 1,849	-	-	$ -	$ -	
	TOTAL NET GENERATION	3,022.0	641,610	6,540,302	$ 26,573,080	29.49%	10.194	$ 4.063	$ 41.42	44.64%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		405,747	N/A	16,161,673	N/A	N/A	N/A	39.83	28.23%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		405,747		$ 16,161,673				$ 39.83	28.23%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		389,955	N/A	4,975,018	N/A	N/A	N/A	12.76	27.13%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		389,955		$ 4,975,018				$ 12.76	27.13%
	TOTAL PURCHASES		795,702		$ 21,136,691				$ 26.56	55.36%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,437,312		$ 47,709,771				$ 33.19	100.00%
DISPOSITION OF ENERGY:	Sales to Ultimate Consumer		1,228,038							85.44%
	Sales for Resale	-	104,482							7.27%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,404							0.10%
	TOTAL @ THE METER		1,333,924							92.81%
	Total Energy Losses		103,388							7.19%
	Percent Losses									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	(1)	(12)	$ (223)	N/A	-	$ 18.130	$ 223.00	0.00%
	Nelson 6	385.0	555	5,906	102,753	N/A	10.641	17.399	185.14	0.04%
	Sabine	1,890.0	1	14	249	N/A	13.810	18.030	249.00	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		555	5,907	$ 102,779		10.643	$ 17.399	$ 185.19	0.04%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

(2) Other Non-Firm Purchases are net of off-system sales: 383,647 mWh

$ 19,945,278

Control Number: 39036

Item Number: 56

Addendum StartPage: 0

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF MAY 2011

Current System Fuel Factor: (1)

TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
Fuel Cost	501	$ 37,920,148	$ 181,644	$ 38,101,792
Allowances	509	$ 3,670	$ -	$ 3,670
Purchased Power Cost - Nuclear	555	1,854,099	9,607,404	11,461,503
Purchased Power Cost - Non-Nuclear	555	42,332,832	11,789,115	54,121,947
TOTAL SYSTEM COST:		$ 82,110,749	$ 21,578,163	$ 103,688,912
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	15,834,642	4,268,192	20,102,834
NET SYSTEM COST:		$ 66,276,107	$ 17,309,971	$ 83,586,078
Texas Fixed Fuel Factor Allocator		92.098%	92.098%	92.098%
100% Renewable Energy Credits	447	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 61,038,969	$ 15,942,137	$ 76,981,106

TEXAS FIXED FUEL FACTOR RELATED REVENUES:	ACCOUNT	REVENUES	MWH SALES
Residential	440	$ 17,288,397	414,642
Commercial & Industrial	442	33,141,027	829,024
Street & Highway	444	282,275	6,770
Public Authorities	445	856,586	20,853
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 51,568,285	1,271,289

OVER/(UNDER) RECOVERY OF COSTS:	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
	Annual Interest Compound Rate (%):		0.28%	
Beginning Cumulative Balance	182	42,130,311	(10,682,091)	31,448,220
Entry This Month	182	(9,470,684)	7,329	(9,463,355)
Docket No. 38967 Refund	182	(23,171)	(634)	(23,805)
	182			-
	182			-
Ending Cumulative Balance	182	$ 32,636,456	$ (10,675,396)	$ 21,961,060

Comments:
(1) The Texas retail fixed fuel factor is 4.03008 cents/kWh effective with March 2011 billing cycles.
(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF MAY 2011

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,975,916	$ 4,436,144	$ 2.245	116,477	$ 38.086	8,482.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	-	(1,080)	#DIV/0!	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	2,715,490	8,303,426	3.058	163,829	50.683	8,287.6
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	6,749	132,470	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	-	-	-	-	-	-
				TOTAL COAL:	4,698,155	$ 12,870,960	$ 2.740	280,306	$ 45.918	8,380.4
CENTERPOINT	NG	SPOT		Sabine	60,000	$ 266,405	$ 4.440			
CITIGROUP	NG	SPOT		Sabine	40,000	178,653	4.466			
DCP MIDSTREAM	NG	SPOT		Sabine	1,110,000	4,954,351	4.463			
ENBRIDGE	NG	SPOT		Sabine	2,925,171	12,846,982	4.392			
ETC MARKETING	NG	SPOT		Sabine	370,000	1,621,217	4.382			
JP MORGAN VNTRS	NG	SPOT		Sabine	215,000	953,704	4.436			
KMTEJAS	NG	SPOT		Sabine	40,000	188,237	4.706			
ONEOK EM&T	NG	SPOT		Sabine	340,000	1,490,614	4.384			
SEQUENT	NG	SPOT		Sabine	15,000	66,845	4.456			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	3,723	203,088	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	5,118,894	$ 22,770,095	$ 4.448			
BGEM	NG	SPOT		Lewis Creek	232,500	$ 1,009,050	$ 4.340			
ENBRIDGE	NG	SPOT		Lewis Creek	840,000	3,703,913	4.409			
JP MORGAN VNTRS	NG	SPOT		Lewis Creek	340,000	1,466,210	4.312			
ONEOK EM&T	NG	SPOT		Lewis Creek	20,000	88,119	4.406			
SEQUENT	NG	SPOT		Lewis Creek	540,000	2,345,770	4.344			
SW ENERGY	NG	SPOT		Lewis Creek	175,000	746,500	4.266			
TETCO	NG	SPOT		Lewis Creek	-	109,500				
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek	-	-	-			
Prior Period Adjustments	NG	N/A		Lewis Creek	(18,312)	(72,923)	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	2,129,188	$ 9,396,139	$ 4.413			
				TOTAL NATURAL GAS & OIL	7,248,082	$ 32,166,234	$ 4.438			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF MAY 2011

Time Period: 744 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
COAL/OIL:	Nelson 6	385.0	105,212	1,123,393	$ 3,202,610	36.73%	10.677	$ 2.851	$ 30.44	6.46%
	Big Cajun No. 2 Unit 3	227.0	59,857	611,497	1,325,006	35.44%	10.216	2.167	22.14	3.68%
	Prior Period Adjustments		-	-	-	-	-	-	-	0 00%
	TOTAL COAL/OIL	612.0	165,069	1,734,890	$ 4,527,616	36.25%	10.510	$ 2.610	$ 27.43	10 14%
GAS/OIL:	Lewis Creek	520.0	194,028	2,147,500	$ 9,469,062	50.15%	11.068	$ 4.409	$ 48.80	11.92%
	Sabine	1,890.0	458,649	5,191,051	22,874,515	32.62%	11.318	4.407	49.87	28.17%
	Prior Period Adjustments		-	212,230	1,048,955	-	-	-	-	0.00%
	TOTAL GAS/OIL	2,410.0	652,677	7,550,781	$ 33,392,532	36.40%	11.569	$ 4.422	$ 51.16	40.08%
EMISSIONS & GAINS	509 & 411	-	-	-	3,670	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0 00%
	TOTAL EMISSIONS	-	-	-	$ 3,670	-	-	$ -	$ -	
	TOTAL NET GENERATION	3,022.0	817,746	9,285,671	$ 37,923,818	36.37%	11.355	$ 4.084	$ 46.38	50.22%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		283,551	N/A	11,165,299	N/A	N/A	N/A	39.38	17.41%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		283,551		$ 11,165,299				$ 39.38	17.41%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		527,128	N/A	17,186,990	N/A	N/A	N/A	32.60	32.37%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0 00%
	TOTAL OTHER		527,128		$ 17,186,990				$ 32.60	32.37%
	TOTAL PURCHASES		810,679		$ 28,352,289				$ 34.97	49.78%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,628,425		$ 66,276,107				$ 40.70	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,303,260							80.03%
	Sales for Resale	-	85,374							5.24%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,523							0.09%
	TOTAL @ THE METER		1,390,157							85.36%
	Total Energy Losses		238,268							14.64%
	Percent Losses									
FUEL OIL:	(Included in the above generation)									
	Big Cajun No. 2 Unit 3	227.0	(357)	(3,650)	$ 73,724	N/A	-	$ (20.199)	$ (206.51)	-0.02%
	Nelson 6	385.0	199	2,124	38,678	N/A	10.672	18.212	194.36	0.01%
	Sabine	1,890.0	1	17	313	N/A	17.170	18.229	313.00	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		(157)	(1,509)	$ 112,715		9.611	$ (74.699)	$ (717.93)	-0.01%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

(2) Other Non-Firm Purchases are net of off-system sales: 414,091 mWh

$ 15,834,642

Control Number: 39036

Item Number: 69

Addendum StartPage: 0

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PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF June 2011

Current System Fuel Factor: (1)

	ACCOUNT	RECONCILABLE	NON-RECONCILABL	TOTAL
TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:				
Fuel Cost	501	$ 36,779,344	$ 150,798	$ 36,930,142
Allowances	509	$ 3,265	$ -	$ 3,265
Purchased Power Cost - Nuclear	555	1,548,274	10,053,670	11,601,944
Purchased Power Cost - Non-Nuclear	555	59,067,163	13,607,611	72,674,774
TOTAL SYSTEM COST:		$ 97,398,046	$ 23,812,079	$ 121,210,125
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	23,957,662	5,138,702	29,096,364
NET SYSTEM COST:		$ 73,440,384	$ 18,673,377	$ 92,113,761
Texas Fixed Fuel Factor Allocator		92.537%	92 537%	92.537%
Net Adjustment for Interruptible Load per FERC Docket Nos. EL00-66-014 & EL95-33-010	447/555	27,298	-	27,298
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 67,986,826	$ 17,279,783	$ 85,266,609

	ACCOUNT	REVENUES	MWH SALES
TEXAS FIXED FUEL FACTOR RELATED REVENUES:			
Residential	440	$ 23,722,804	568,967
Commercial & Industrial	442	36,467,523	910,052
Street & Highway	444	283,300	6,795
Public Authorities	445	942,566	22,955
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 61,416,193	1,508,769

	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
OVER/(UNDER) RECOVERY OF COSTS:				
Annual Interest Compound Rate (%):			0.28%	
Beginning Cumulative Balance	182	32,636,456	(10,675,396)	21,961,060
Entry This Month	182	(6,570,633)	5,118	(6,565,515)
	182			-
	182			-
	182			-
Ending Cumulative Balance	182	$ 26,065,823	$ (10,670,278)	$ 15,395,545

Comments:
(1) The Texas retail fixed fuel factor is 4.03008 cents/kWh effective with March 2011 billing cycles.
(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

69

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF June 2011

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,430,481	$ 3,289,645	$ 2.300	84,704	$ 38.837	8,444.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	1,299	28,334	21.812	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	2,461,119	7,084,983	2.879	140,970	50.259	8,729.2
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	6,758	#DIV/0!	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	-	129,986	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	-	-	-	-	-	-
				TOTAL COAL:	3,892,899	$ 10,539,706	$ 2.707	225,674	$ 46.703	8,625.0
CENTERPOINT	NG	SPOT		Sabine	740,000	$ 3,355,243	$ 4.534			
CITIGROUP	NG	SPOT		Sabine	55,000	257,834	4.688			
CONOCO	NG	SPOT		Sabine	30,000	136,386	4.546			
DCP MIDSTREAM	NG	SPOT		Sabine	1,110,000	4,970,915	4.478			
ENBRIDGE	NG	SPOT		Sabine	2,336,130	10,340,706	4.426			
ETC MARKETING	NG	SPOT		Sabine	100,000	482,830	4.828			
JLA ENERGY	NG	SPOT		Sabine	60,000	274,398	4.573			
JP MORGAN VNTRS	NG	SPOT		Sabine	265,000	1,202,048	4.536			
KMTEJAS	NG	SPOT		Sabine	30,000	137,199	4.573			
NJR	NG	SPOT		Sabine	10,000	44,512	4.451			
ONEOK EM&T	NG	SPOT		Sabine	20,000	99,166	4.958			
SEQUENT	NG	SPOT		Sabine	115,000	532,634	4.632			
TAUBER	NG	SPOT		Sabine	20,000	90,017	4.501			
Prior Period Adjustments	NG	N/A		Sabine	12,740	257,080	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	4,903,870	$ 22,180,968	$ 4.523			
BGEM	NG	SPOT		Lewis Creek	450,000	$ 1,930,500	$ 4.290			
ENBRIDGE	NG	SPOT		Lewis Creek	780,000	3,531,572	4.528			
JP MORGAN VNTRS	NG	SPOT		Lewis Creek	45,000	194,368	4.319			
NJR	NG	SPOT		Lewis Creek	300,000	1,285,950	4.287			
ONEOK EM&T	NG	SPOT		Lewis Creek	20,000	86,280	4.314			
SEQUENT	NG	SPOT		Lewis Creek	340,000	1,467,050	4.315			
SW ENERGY	NG	SPOT		Lewis Creek	210,000	974,920	4.642			
TAUBER	NG	SPOT		Lewis Creek	30,000	130,895	4.363			
TETCO	NG	SPOT		Lewis Creek	-	109,500				
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek	-	-	-			
Prior Period Adjustments	NG	N/A		Lewis Creek	33,138	153,238	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	2,208,138	$ 9,864,273	$ 4.467			
				TOTAL NATURAL GAS & OIL	7,112,008	$ 32,045,241	$ 4.506			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF June 2011

Time Period: 720 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
COAL/OIL:	Nelson 6	385.0	100,673	1,015,313	$ 2,911,228	36.32%	10.085	$ 2.867	$ 28.92	5.35%
	Big Cajun No. 2 Unit 3	227.0	64,607	673,031	1,403,810	39.53%	10.417	2.086	21.73	3.43%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	165,280	1,688,343	$ 4,315,038	37.51%	10.215	$ 2 556	$ 26.11	8.78%
GAS/OIL:	Lewis Creek	520.0	199,541	2,175,000	$ 9,711,035	53.30%	10.900	$ 4.465	$ 48.67	10.60%
	Sabine	1,890.0	451,026	4,955,432	22,184,608	33.14%	10.987	4.477	49.19	23.97%
	Prior Period Adjustments		-	84,960	568,663	-	-	-	-	0.00%
	TOTAL GAS/OIL	2,410.0	650,567	7,215,392	$ 32,464,306	37.49%	11.091	$ 4.499	$ 49.90	34.57%
EMISSIONS & GAINS	509 & 411	-	-	-	3,265	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 3,265	-	-	$ -	$ -	
	TOTAL NET GENERATION	3,022.0	815,847	8,903,735	$ 36,782,609	37.50%	10.913	$ 4.131	$ 45.09	43.36%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		280,087	N/A	10,931,276	N/A	N/A	N/A	39.03	14.89%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		280,087		$ 10,931,276				$ 39.03	14.89%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		785,732	N/A	25,726,499	N/A	N/A	N/A	32.74	41.76%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		785,732		$ 25,726,499				$ 32.74	41.76%
	TOTAL PURCHASES		1,065,819		$ 36,657,775				$ 34.39	56.64%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,881,666		$ 73,440,384				$ 39.03	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,569,161							83.39%
	Sales for Resale	-	71,061							3.78%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,675							0.09%
	TOTAL @ THE METER		1,641,897							87.26%
	Total Energy Losses		239,769							12.74%
	Percent Losses									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	41	423	$ 8,824	N/A	10.308	$ 20.879	$ 215.22	0.00%
	Nelson 6	385.0	215	2,166	40,236	N/A	10.075	18.575	187.14	0.01%
	Sabine	1,890.0	2	24	436	N/A	11.975	18.205	218 00	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0 00%
	TOTAL OIL		258	2,613	$ 49,496		10.127	$ 18.944	$ 191.84	0.01%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

(2) Other Non-Firm Purchases are net of off-system sales. 382,132 mWh
$ 23,957,662

Control Number: 39036

Item Number: 70

Addendum StartPage: 0

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PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF July 2011

Current System Fuel Factor: (1)

TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:	ACCOUNT	RECONCILABLE	NON-RECONCILABL	TOTAL
Fuel Cost	501	$ 41,020,920	$ 150,042	$ 41,170,962
Allowances	509	$ 3,422	$ -	$ 3,422
Purchased Power Cost - Nuclear	555	1,837,137	9,918,350	11,755,487
Purchased Power Cost - Non-Nuclear	555	55,386,775	12,989,208	68,375,983
TOTAL SYSTEM COST:		$ 98,248,254	$ 23,057,600	$ 121,305,854
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	22,037,836	5,023,833	27,061,669
NET SYSTEM COST:		$ 76,210,418	$ 18,033,767	$ 94,244,185
Texas Fixed Fuel Factor Allocator		91.161%	91.161%	91.161%
	447/555	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 69,474,179	$ 16,439,762	$ 85,913,941

TEXAS FIXED FUEL FACTOR RELATED REVENUES:	ACCOUNT	REVENUES	MWH SALES
Residential	440	$ 28,578,417	685,421
Commercial & Industrial	442	37,024,144	923,076
Street & Highway	444	285,418	6,845
Public Authorities	445	976,863	23,789
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 66,864,842	1,639,131

OVER/(UNDER) RECOVERY OF COSTS:	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
Annual Interest Compound Rate (%):			0.28%	
Beginning Cumulative Balance	182	26,065,823	(10,670,278)	15,395,545
Entry This Month	182	(2,609,337)	3,588	(2,605,749)
	182			-
	182			-
	182			-
Ending Cumulative Balance	182	$ 23,456,486	$ (10,666,690)	$ 12,789,796

Comments:
(1) The Texas retail fixed fuel factor is 4.03008 cents/kWh effective with March 2011 billing cycles.
(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF July 2011

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,561,675	$ 3,547,045	$ 2.271	92,659	$ 38.281	8,427.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	3,585	81,275	22.671	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	1,980,723	5,823,060	2.940	112,498	51.761	8,803.4
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	-	158,999	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	-	-	-	-	-	-
				TOTAL COAL:	3,545,983	$ 9,610,379	$ 2.710	205,157	$ 46.844	8,642.1
CENTERPOINT	NG	SPOT		Sabine	20,000	$ 90,189	$ 4.509			
CITIGROUP	NG	SPOT		Sabine	35,000	153,465	4.385			
DCP MIDSTREAM	NG	SPOT		Sabine	3,430,000	15,005,578	4.375			
ENBRIDGE	NG	SPOT		Sabine	1,750,096	7,798,932	4.456			
ETC MARKETING	NG	SPOT		Sabine	60,000	269,668	4.494			
JP MORGAN VNTRS	NG	SPOT		Sabine	190,000	831,313	4.375			
KMTEJAS	NG	SPOT		Sabine	20,000	91,289	4.564			
SEQUENT	NG	SPOT		Sabine	260,000	1,149,745	4.422			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
				Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	1,709	(227,185)	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	5,766,805	$ 25,162,996	$ 4.363			
BGEM	NG	SPOT		Lewis Creek	475,090	$ 2,076,631	$ 4.371			
ENBRIDGE	NG	SPOT		Lewis Creek	900,000	4,068,352	4.520			
JLA ENERGY	NG	SPOT		Lewis Creek	50,000	219,700	4.394			
JP MORGAN VNTRS	NG	SPOT		Lewis Creek	250,000	1,108,050	4.432			
NJR	NG	SPOT		Lewis Creek	475,000	2,106,326	4.434			
SEQUENT	NG	SPOT		Lewis Creek	125,000	551,875	4.415			
SW ENERGY	NG	SPOT		Lewis Creek	125,001	548,529	4.388			
TETCO	NG	SPOT		Lewis Creek	-	109,500				
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek	-	-	-			
Prior Period Adjustments	NG	N/A		Lewis Creek	36,425	155,120	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	2,436,516	$ 10,944,083	$ 4.492			
				TOTAL NATURAL GAS & OIL	8,203,321	$ 36,107,079	$ 4.402			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF July 2011

Time Period: 744 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
COAL/OIL:	Nelson 6	385.0	114,443	1,284,028	$ 3,758,108	39.95%	11.220	$ 2.927	$ 32.84	5.94%
	Big Cajun No. 2 Unit 3	227.0	77,692	824,266	1,872,869	46.00%	10.609	2.272	24.11	4.03%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	192,135	2,108,294	$ 5,630,977	42.20%	10.973	$ 2.671	$ 29.31	9.97%
GAS/OIL:	Lewis Creek	520.0	216,369	2,400,091	$ 10,788,963	55.93%	11.093	$ 4.495	$ 49.86	11.22%
	Sabine	1,890.0	484,669	5,551,100	24,484,905	34.47%	11.453	4.411	50.52	25.14%
	Prior Period Adjustments		-	84,620	116,075	-	-	-	-	0.00%
	TOTAL GAS/OIL	2,410.0	701,038	8,035,811	$ 35,389,943	39.10%	11.463	$ 4 404	$ 50.48	36.36%
EMISSIONS & GAINS	509 & 411	-	-	-	3,422	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 3,422	-	-	$ -	$ -	
	TOTAL NET GENERATION	3,022.0	893,173	10,144,105	$ 41,024,342	39.73%	11.357	$ 4.044	$ 45.93	46.33%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		285,578	N/A	11,666,550	N/A	N/A	N/A	40.85	14.81%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		285,578		$ 11,666,550				$ 40.85	14.81%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		749,132	N/A	23,519,526	N/A	N/A	N/A	31.40	38.86%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		749,132		$ 23,519,526				$ 31.40	38.86%
	TOTAL PURCHASES		1,034,710		$ 35,186,076				$ 34.01	53.67%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,927,883		$ 76,210,418				$ 39.53	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,690,935							87.71%
	Sales for Resale	-	117,899							6.12%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,714							0.09%
	TOTAL @ THE METER		1,810,548							93.92%
	Total Energy Losses		117,335							6.08%
	Percent Losses									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	559	5,931	$ 151,070	N/A	10.610	$ 25.472	$ 270.25	0.03%
	Nelson 6	385.0	495	5,556	103,197	N/A	11.224	18.574	208.48	0.03%
	Sabine	1,890.0	2	28	502	N/A	13.775	18.221	251.00	0 00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		1,056	11,514	$ 254,769		10.904	$ 22.126	$ 241.26	0.06%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month

(2) Other Non-Firm Purchases are net of off-system sales: 414,420 mWh
$ 22,037,836

Control Number: 39036

Item Number: 87

Addendum StartPage: 0

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF August 2011

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Current System Fuel Factor: (1)

	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:				
Fuel Cost	501	$ 41,321,640	$ 326,732	$ 41,648,372
Allowances	509	$ 10,533	$ -	$ 10,533
Purchased Power Cost - Nuclear	555	1,844,804	9,660,580	11,505,384
Purchased Power Cost - Non-Nuclear	555	56,520,352	12,903,368	69,423,720
TOTAL SYSTEM COST:		$ 99,697,329	$ 22,890,680	$ 122,588,009
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	20,098,301	5,566,903	25,665,204
NET SYSTEM COST:		$ 79,599,028	$ 17,323,777	$ 96,922,805
Texas Fixed Fuel Factor Allocator		92.009%	92.009%	92.009%
	447/555	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 73,238,270	$ 15,939,434	$ 89,177,704

	ACCOUNT	REVENUES	MWH SALES
TEXAS FIXED FUEL FACTOR RELATED REVENUES:			
Residential	440	$ 29,245,421	701,406
Commercial & Industrial	442	38,518,384	960,749
Street & Highway	444	282,097	6,766
Public Authorities	445	963,780	23,445
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 69,009,682	1,692,366

	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
OVER/(UNDER) RECOVERY OF COSTS:				
Annual Interest Compound Rate (%):			0.28%	
Beginning Cumulative Balance	182	23,456,486	(10,666,690)	12,789,796
Entry This Month	182	(4,228,588)	2,980	(4,225,608)
	182			-
	182			-
	182			-
Ending Cumulative Balance	182	$ 19,227,898	$ (10,663,710)	$ 8,564,188

Comments:

(1) The Texas retail fixed fuel factor is 4.03008 cents/kWh effective with March 2011 billing cycles.

(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

87

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF August 2011

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,733,722	$ 3,993,383	$ 2.303	103,210	$ 38.692	8,399.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	(1,489)	(33,955)	22.804	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	1,955,546	5,638,243	2.883	112,517	50.110	8,690.0
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	-	158,999	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	-	-	-	-	-	-
				TOTAL COAL:	3,687,779	$ 9,756,670	$ 2.646	215,727	$ 45.227	8,547.3
CENTERPOINT	NG	SPOT		Sabine	100,000	$ 423,875	$ 4.239			
CITIGROUP	NG	SPOT		Sabine	120,000	489,922	4.083			
DCP MIDSTREAM	NG	SPOT		Sabine	1,335,000	5,910,799	4.428			
ENBRIDGE	NG	SPOT		Sabine	2,667,513	11,481,268	4.304			
ETC MARKETING	NG	SPOT		Sabine	40,000	170,130	4.253			
JP MORGAN VNTRS	NG	SPOT		Sabine	30,000	121,459	4.049			
KINDER	NG	SPOT		Sabine	20,000	82,915	4.146			
KMTEJAS	NG	SPOT		Sabine	930,000	4,185,696	4.501			
NJR	NG	SPOT		Sabine	24,000	97,425	4.059			
SEQUENT	NG	SPOT		Sabine	495,000	2,061,730	4.165			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
				Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	(32,290)	98,214	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	5,729,223	$ 25,123,432	$ 4.385			
COPANO	NG	SPOT		Lewis Creek	20,000	$ 84,225	$ 4.211			
ENBRIDGE	NG	SPOT		Lewis Creek	915,000	4,024,909	4.399			
JLA ENERGY	NG	SPOT		Lewis Creek	20,000	83,800	4.190			
JP MORGAN VNTRS	NG	SPOT		Lewis Creek	260,000	1,056,040	4.062			
NJR	NG	SPOT		Lewis Creek	320,000	1,303,470	4.073			
ONEOK EM&T	NG	SPOT		Lewis Creek	50,000	199,775	3.996			
SEQUENT	NG	SPOT		Lewis Creek	570,000	2,429,770	4.263			
SW ENERGY	NG	SPOT		Lewis Creek	290,000	1,190,925	4.107			
TETCO	NG	SPOT		Lewis Creek	-	109,500				
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek	-	-	-			
Prior Period Adjustments	NG	N/A		Lewis Creek	13,319	60,874	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	2,458,319	$ 10,543,288	$ 4.289			
				TOTAL NATURAL GAS & OIL	8,187,542	$ 35,666,720	$ 4.356			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF August 2011

Time Period: 744 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
COAL/OIL:	Nelson 6	385.0	120,651	1,329,810	$ 3,802,292	42.12%	11.022	$ 2.859	$ 31.51	5.91%
	Big Cajun No. 2 Unit 3	227.0	76,335	802,020	1,576,799	45.20%	10.507	1.966	20.66	3.74%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	196,986	2,131,830	$ 5,379,091	43.26%	10.822	$ 2.523	$ 27.31	9.65%
GAS/OIL:	Lewis Creek	520.0	222,963	2,445,000	$ 10,482,414	57.63%	10.966	$ 4.287	$ 47.01	10.93%
	Sabine	1,890.0	520,823	5,767,585	25,050,091	37.04%	11.074	4.343	48.10	25.52%
	Prior Period Adjustments		-	41,337	410,044	-	-	-	-	0.00%
	TOTAL GAS/OIL	2,410.0	743,786	8,253,922	$ 35,942,549	41.48%	11.097	$ 4.355	$ 48.32	36.45%
EMISSIONS & GAINS	509 & 411	-	-	-	10,533	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 10,533	-	-	$ -	$ -	
	TOTAL NET GENERATION	3,022.0	940,772	10,385,752	$ 41,332,173	41.84%	11.040	$ 3.980	$ 43.93	46.10%
PURCHASES:	Firm Cogen: (1)		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		356,015	N/A	13,726,138	N/A	N/A	N/A	38.55	17.45%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		356,015		$ 13,726,138				$ 38.55	17.45%
	Other Firm		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Other Non-Firm (2)		743,731	N/A	24,540,717	N/A	N/A	N/A	33.00	36.45%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		743,731		$ 24,540,717				$ 33.00	36.45%
	TOTAL PURCHASES		1,099,746		$ 38,266,855				$ 34.80	53.90%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		2,040,518		$ 79,599,028				$ 39.01	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,733,147							84.94%
	Sales for Resale	-	117,228							5.75%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,877							0.09%
	TOTAL @ THE METER		1,852,252							90.78%
	Total Energy Losses		188,266							9.22%
	Percent Losses									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	(201)	(2,115)	$ (69,921)	N/A	-	$ 33.054	$ 347.87	-0.01%
	Nelson 6	385.0	-	-	-	N/A	-	-	-	0.00%
	Sabine	1,890.0	2	19	344	N/A	9.440	18.220	172.00	0 00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		(199)	(2,096)	$ (69,577)		10 535	$ 33.187	$ 349 63	-0.01%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

(2) Other Non-Firm Purchases are net of off-system sales: 448,817 mWh
$ 20,098,301

Control Number: 39036

Item Number: 107

Addendum StartPage: 0

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF SEPTEMBER 2011

Current System Fuel Factor: (1)

	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:				
Fuel Cost	501	$ 33,979,854	$ 240,312	$ 34,220,166
Allowances	509	$ 3,371	$ -	$ 3,371
Purchased Power Cost - Nuclear	555	1,777,210	10,237,714	12,014,924
Purchased Power Cost - Non-Nuclear	555	37,562,989	11,643,749	49,206,738
TOTAL SYSTEM COST:		$ 73,323,424	$ 22,121,775	$ 95,445,199
Gains from Disposition of Allowances	411	$ 106	$ -	$ 106
(2) Sales for Resale Revenue	447	18,940,173	5,031,906	23,972,079
NET SYSTEM COST:		$ 54,383,145	$ 17,089,869	$ 71,473,014
Texas Fixed Fuel Factor Allocator		92.602%	92.602%	92.602%
	447/555	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 50,359,880	$ 15,825,560	$ 66,185,440

	ACCOUNT	REVENUES	MWH SALES
TEXAS FIXED FUEL FACTOR RELATED REVENUES:			
Residential	440	$ 28,547,279	685,119
Commercial & Industrial	442	37,995,658	947,672
Street & Highway	444	284,476	6,827
Public Authorities	445	985,736	24,019
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 67,813,149	1,663,637

	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
OVER/(UNDER) RECOVERY OF COSTS:				
Annual Interest Compound Rate (%):			0.28%	
Beginning Cumulative Balance	182	19,227,898	(10,663,710)	8,564,188
Entry This Month	182	17,453,269	1,996	17,455,265
	182			-
	182			-
	182			-
Ending Cumulative Balance	182	$ 36,681,167	$ (10,661,714)	$ 26,019,453

Comments:

(1) The Texas retail fixed fuel factor is 4.02739 cents/kWh effective with September 2011 billing cycles.

(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

107

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF SEPTEMBER 2011

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,420,854	$ 3,244,827	$ 2.284	84,124	$ 38.572	8,445.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	(8)	(197)	24.625	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	2,173,017	6,442,726	2.965	122,683	52.515	8,856.2
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	-	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	(47,914)	-	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	-	-	-	-	-	-
				TOTAL COAL:	3,545,949	$ 9,687,356	$ 2.732	206,807	$ 46.842	8,573.1
CENTERPOINT	NG	SPOT		Sabine	310,000	$ 1,270,138	$ 4.097			
CITIGROUP	NG	SPOT		Sabine	30,000	115,278	3.843			
DCP MIDSTREAM	NG	SPOT		Sabine	1,220,000	4,973,509	4.077			
ENBRIDGE	NG	SPOT		Sabine	1,966,488	7,933,942	4.035			
ETC MARKETING	NG	SPOT		Sabine	450,000	1,843,676	4.097			
JP MORGAN VNTRS	NG	SPOT		Sabine	60,000	232,206	3.870			
KINDER	NG	SPOT		Sabine	900,000	3,682,851	4.092			
NJR	NG	SPOT		Sabine	10,000	39,093	3.909			
SEQUENT	NG	SPOT		Sabine	135,000	539,122	3.993			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
				Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	(14,367)	79,332	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	5,067,121	$ 20,709,146	$ 4.087			
BGEM	NG	SPOT		Lewis Creek	145,000	$ 575,450	$ 3.969			
ENBRIDGE	NG	SPOT		Lewis Creek	815,000	3,325,954	4.081			
JP MORGAN VNTRS	NG	SPOT		Lewis Creek	120,000	471,880	3.932			
NJR	NG	SPOT		Lewis Creek	295,000	1,184,181	4.014			
SEQUENT	NG	SPOT		Lewis Creek	340,000	1,308,545	3.849			
SW ENERGY	NG	SPOT		Lewis Creek	90,000	355,900	3.954			
TETCO	NG	SPOT		Lewis Creek	-	109,500				
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek	-	-	-			
Prior Period Adjustments	NG	N/A		Lewis Creek	39,577	274,267	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	1,844,577	$ 7,605,677	$ 4.123			
		TOTAL NATURAL GAS & OIL			6,911,698	$ 28,314,823	$ 4.097			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF SEPTEMBER 2011

Time Period: 720 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
COAL/OIL:	Nelson 6	385.0	112,894	1,257,648	$ 3,676,274	40.73%	11.140	$ 2.923	$ 32.56	6.98%
	Big Cajun No. 2 Unit 3	227.0	63,570	653,721	1,345,812	38.90%	10.283	2.059	21.17	3.93%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	176,464	1,911,369	$ 5,022,086	40.05%	10.831	$ 2.627	$ 28.46	10.91%
GAS/OIL:	Lewis Creek	520.0	158,126	1,805,000	$ 7,331,411	42.23%	11.415	$ 4.062	$ 46.36	9.78%
	Sabine	1,890.0	457,573	5,120,618	20,788,555	33.63%	11.191	4.060	45.43	28.29%
	Prior Period Adjustments		-	144,678	837,802	-	-	-	-	0.00%
	TOTAL GAS/OIL	2,410.0	615,699	7,070,296	$ 28,957,768	35.48%	11.483	$ 4.096	$ 47 03	38.06%
EMISSIONS & GAINS	509 & 411	-	-	-	3,265	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 3,265	-	-	$ -	$ -	
	TOTAL NET GENERATION	3,022.0	792,163	8,981,665	$ 33,983,119	36.41%	11.338	$ 3.784	$ 42.90	48.97%
PURCHASES:	Firm Cogen:		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		379,528	N/A	13,437,385	N/A	N/A	N/A	35.41	23.46%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		379,528		$ 13,437,385				$ 35.41	23.46%
	Other Firm (1)		150,727	N/A	5,514,736	N/A	N/A	N/A	$ 36.59	9.32%
	Other Non-Firm (2)		295,264	N/A	1,447,905	N/A	N/A	N/A	4.90	18.25%
	Prior Penod Adjustments		-	N/A	-	N/A	N/A	N/A	-	0 00%
	TOTAL OTHER		445,991		$ 6,962,641				$ 15.61	27.57%
	TOTAL PURCHASES		825,519		$ 20,400,026				$ 24 71	51.03%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,617,682		$ 54,383,145				$ 33.62	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,685,397							104.19%
	Sales for Resale	-	121,920							7.54%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,635							0.10%
	TOTAL @ THE METER		1,808,952							111.83%
	Total Energy Losses		(191,270)							-11.83%
	Percent Losses									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227 0	(31)	(322)	$ (7,419)	N/A	-	$ 23.025	$ 239.32	0.00%
	Nelson 6	385.0	282	3,143	44,595	N/A	11.144	14.190	158.14	0.02%
	Sabine	1,890.0	1	12	222	N/A	12.210	18.182	222.00	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		252	2,833	$ 37,398		11.241	$ 13.202	$ 148.40	0.02%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

CAPACITY CONTRACT	Expiration Dates
CONOCOPHILIPS-SRW	May 31, 2013
NRG POWER PARTNERS	February 28, 2012

(2) Other Non-Firm Purchases are net of off-system sales: 386,889 mWh
$ 18,940,173

Control Number: 39036

Item Number: 114

Addendum StartPage: 0

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PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF OCTOBER 2011

Current System Fuel Factor: (1)

	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:				
Fuel Cost	501	$ 23,457,763	$ 214,552	$ 23,672,315
Allowances	509	$ 1,584	$ -	$ 1,584
Purchased Power Cost - Nuclear	555	1,856,857	9,631,411	11,488,268
Purchased Power Cost - Non-Nuclear	555	31,308,839	12,255,534	43,564,373
TOTAL SYSTEM COST:		$ 56,625,043	$ 22,101,497	$ 78,726,540
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	13,299,658	4,778,735	18,078,393
NET SYSTEM COST:		$ 43,325,385	$ 17,322,762	$ 60,648,147
Texas Fixed Fuel Factor Allocator		93.867%	93.867%	93.867%
	447/555	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 40,668,239	$ 16,260,357	$ 56,928,596

	ACCOUNT	REVENUES	MWH SALES
TEXAS FIXED FUEL FACTOR RELATED REVENUES:			
Residential	440	$ 20,484,767	491,621
Commercial & Industrial	442	34,202,662	854,066
Street & Highway	444	285,368	6,849
Public Authorities	445	915,713	22,324
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 55,888,510	1,374,860

	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
OVER/(UNDER) RECOVERY OF COSTS:				
Annual Interest Compound Rate (%):			0.28%	
Beginning Cumulative Balance	182	36,681,167	(10,661,714)	26,019,453
Entry This Month	182	15,220,271	6,063	15,226,334
	182			-
	182			-
	182			-
Ending Cumulative Balance	182	$ 51,901,438	$ (10,655,651)	$ 41,245,787

Comments:
(1) The Texas retail fixed fuel factor is 4.02739 cents/kWh effective with September 2011 billing cycles.
(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF OCTOBER 2011

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,770,398	$ 3,963,158	$ 2.239	105,168	$ 37.684	8,417.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	908	20,329	22.389	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	2,696,703	7,801,401	2.893	153,122	50.949	8,805.7
SunCoast Products	Igniter Fuel	Firm		Nelson 6	12,312	257,668	20.928	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	(23,957)	-	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	-	-	-	-	-	-
				TOTAL COAL:	4,456,364	$ 12,042,556	$ 2.702	258,290	$ 46.624	8,626.7
CENTERPOINT	NG	SPOT		Sabine	10,000	$ 35,823	$ 3.582			
CITIGROUP	NG	SPOT		Sabine	65,000	238,033	3.662			
DCP MIDSTREAM	NG	SPOT		Sabine	930,000	3,652,495	3.927			
ENBRIDGE	NG	SPOT		Sabine	2,147,867	8,252,467	3.842			
JP MORGAN VNTRS	NG	SPOT		Sabine	35,000	124,502	3.557			
KMTEJAS	NG	SPOT		Sabine	620,000	2,416,297	3.897			
NJR	NG	SPOT		Sabine	19,000	70,688	3.720			
SEQUENT	NG	SPOT		Sabine	85,000	311,186	3.661			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
				Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	49,411	119,317	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	3,961,278	$ 15,220,808	$ 3.842			
BGEM	NG	SPOT		Lewis Creek	25,000	$ 85,800	$ 3.432			
ENBRIDGE	NG	SPOT		Lewis Creek	330,000	1,274,150	3.861			
JP MORGAN VNTRS	NG	SPOT		Lewis Creek	125,000	431,975	3.456			
SEQUENT	NG	SPOT		Lewis Creek	450,000	1,678,530	3.730			
SW ENERGY	NG	SPOT		Lewis Creek	20,000	72,300	3.615			
TETCO	NG	SPOT		Lewis Creek	-	118,626				
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek	-	-	-			
Prior Period Adjustments	NG	N/A		Lewis Creek	(19,482)	(64,059)	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	930,518	$ 3,597,322	$ 3.866			
		TOTAL NATURAL GAS & OIL			4,891,796	$ 18,818,130	$ 3.847			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF OCTOBER 2011

Time Period: 744 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
COAL/OIL:	Nelson 6	385.0	79,953	921,731	$ 2,678,091	27.91%	11.528	$ 2.906	$ 33.50	5.74%
	Big Cajun No. 2 Unit 3	227.0	70,348	719,314	1,601,420	41.65%	10.225	2.226	22.76	5.05%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	150,301	1,641,045	$ 4,279,511	33.01%	10.918	$ 2.608	$ 28.47	10.79%
GAS/OIL:	Lewis Creek	520.0	78,035	950,000	$ 3,661,381	20.17%	12.174	$ 3.854	$ 46.92	5.60%
	Sabine	1,890.0	343,408	3,957,108	15,284,823	24.42%	11.523	3.863	44.51	24.64%
	Prior Period Adjustments		-	73,585	232,048	-	-	-	-	0.00%
	TOTAL GAS/OIL	2,410.0	421,443	4,980,693	$ 19,178,252	23.50%	11.818	$ 3.851	$ 45.51	30.24%
EMISSIONS & GAINS	509 & 411	-	-	-	1,584	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 1,584	-	-	$ -	$ -	
	TOTAL NET GENERATION	3,022.0	571,744	6,621,738	$ 23,459,347	25.43%	11.582	$ 3.543	$ 41.03	41.03%
PURCHASES:	Firm Cogen:		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		416,205	N/A	14,052,680	N/A	N/A	N/A	33.76	29.87%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		416,205		$ 14,052,680				$ 33.76	29.87%
	Other Firm (1)		20,229	N/A	892,054	N/A	N/A	N/A	$ 44.10	1.45%
	Other Non-Firm (2)		385,373	N/A	4,921,304	N/A	N/A	N/A	12.77	27.65%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		405,602		$ 5,813,358				$ 14.33	29.10%
	TOTAL PURCHASES		821,807		$ 19,866,038				$ 24.17	58.97%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,393,551		$ 43,325,385				$ 31.09	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,387,752							99.58%
	Sales for Resale	-	85,717							6.15%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,499							0.11%
	TOTAL @ THE METER		1,474,968							105.84%
	Total Energy Losses		(81,417)							-5.84%
	Percent Losses									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	507	5,183	$ 117,959	N/A	10.223	$ 22.759	$ 232.66	0.04%
	Nelson 6	385.0	255	2,944	52,174	N/A	11.543	17.725	204.60	0.02%
	Sabine	1,890.0	-	-	-	N/A	-	-	-	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		762	8,127	$ 170,133		10.665	$ 20.935	$ 223.27	0.06%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

CAPACITY CONTRACT	**Expiration Dates**
CONOCOPHILIPS-SRW	May 31, 2013
NRG POWER PARTNERS	February 28, 2012

(2) Other Non-Firm Purchases are net of off-system sales: 285,501 mWh
$ 13,299,658

Control Number: 39036

Item Number: 125

Addendum StartPage: 0

PROJECT NO. 39036

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ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF NOVEMBER 2011

Current System Fuel Factor: (1)

TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
Fuel Cost	501	$ 20,348,715	$ 231,378	$ 20,580,093
Allowances	509	$ 4,199	$ -	$ 4,199
Purchased Power Cost - Nuclear	555	1,796,344	9,372,975	11,169,319
Purchased Power Cost - Non-Nuclear	555	25,194,602	11,641,834	36,836,436
TOTAL SYSTEM COST:		$ 47,343,860	$ 21,246,187	$ 68,590,047
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	12,163,887	6,547,383	18,711,270
NET SYSTEM COST:		$ 35,179,973	$ 14,698,804	$ 49,878,777
Texas Fixed Fuel Factor Allocator		93.399%	93.399%	93.399%
	447/555	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 32,857,743	$ 13,728,536	$ 46,586,279

TEXAS FIXED FUEL FACTOR RELATED REVENUES:	ACCOUNT	REVENUES	MWH SALES
Residential	440	$ 14,930,921	358,332
Commercial & Industrial	442	31,420,717	785,910
Street & Highway	444	285,980	6,863
Public Authorities	445	820,147	19,976
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 47,457,765	1,171,081

OVER/(UNDER) RECOVERY OF COSTS:	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
Annual Interest Compound Rate (%):			0.28%	
Beginning Cumulative Balance	182	51,901,438	(10,655,651)	41,245,787
Entry This Month	182	14,600,022	9,612	14,609,634
	182			-
	182			-
	182			-
Ending Cumulative Balance	182	$ 66,501,460	$ (10,646,039)	$ 55,855,421

Comments:

(1) The Texas retail fixed fuel factor is 4.02739 cents/kWh effective with September 2011 billing cycles.

(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail. Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

125

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF NOVEMBER 2011

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	1,464,960	$ 3,387,868	$ 2.313	86,684	$ 39.083	8,450.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	2,743	60,290	21.980	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	3,389,366	9,502,311	2.804	153,122	62.057	11,067.5
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	2,577	N/A	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	(23,957)	-	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	-	-	-	-	-	-
				TOTAL COAL:	4,833,112	$ 12,953,046	$ 2.680	239,806	$ 54.015	10,077.1
CITIGROUP	NG	SPOT		Sabine	20,000	$ 70,250	$ 3.512			
DCP MIDSTREAM	NG	SPOT		Sabine	600,000	2,175,231	3.625			
ENBRIDGE	NG	SPOT		Sabine	2,138,744	7,660,327	3.582			
JP MORGAN VNTRS	NG	SPOT		Sabine	15,000	54,562	3.637			
KMTEJAS	NG	SPOT		Sabine	600,000	2,175,231	3.625			
NJR	NG	SPOT		Sabine	10,000	32,325	3.232			
SEQUENT	NG	SPOT		Sabine	180,000	617,775	3.432			
	NG	SPOT		Sabine			-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
				Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	9,748	128,475	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	3,573,492	$ 12,914,176	$ 3.614			
COPANO	NG	SPOT		Lewis Creek	4,000	$ 13,140	$ 3.285			
ENBRIDGE	NG	SPOT		Lewis Creek	260,000	943,275	3.628			
JP MORGAN VNTRS	NG	SPOT		Lewis Creek	70,000	223,273	3.190			
KMTEJAS	NG	SPOT		Lewis Creek	30,000	101,500	3.383			
SEQUENT	NG	SPOT		Lewis Creek	425,000	1,489,220	3.504			
SW ENERGY	NG	SPOT		Lewis Creek	30,000	95,000	3.167			
TETCO	NG	SPOT		Lewis Creek	-	118,626				
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek	-	-	-			
Prior Period Adjustments	NG	N/A		Lewis Creek	(47,132)	(162,266)	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	771,868	$ 2,821,768	$ 3.656			
				TOTAL NATURAL GAS & OIL	4,345,360	$ 15,735,944	$ 3.621			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF NOVEMBER 2011

Time Period: 720 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
COAL/OIL:	Nelson 6	385.0	109,977	1,209,800	$ 3,400,945	39.67%	11.000	$ 2.811	$ 30.92	8.71%
	Big Cajun No. 2 Unit 3	227.0	68,797	688,094	1,466,480	42.09%	10.002	2.131	21.32	5.45%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	178,774	1,897,894	$ 4,867,425	40.57%	10.616	$ 2.565	$ 27.23	14.16%
GAS/OIL:	Lewis Creek	520.0	69,542	819,000	$ 2,984,034	18.57%	11.777	$ 3.644	$ 42.91	5.51%
	Sabine	1,890.0	323,777	3,599,948	12,932,311	23.79%	11.119	3.592	39.94	25.65%
	Prior Period Adjustments		-	(143,709)	(435,055)	-	-	-	-	0.00%
	TOTAL GAS/OIL	2,410.0	393,319	4,275,239	$ 15,481,290	22.67%	10.870	$ 3.621	$ 39.36	31.16%
EMISSIONS & GAINS	509 & 411	-	-	-	4,199	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 4,199	-	-	$ -	$ -	
	TOTAL NET GENERATION	3,022.0	572,093	6,173,133	$ 20,352,914	26.29%	10.790	$ 3.297	$ 35.58	45.32%
PURCHASES:	Firm Cogen:		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		417,234	N/A	13,412,842	N/A	N/A	N/A	32.15	33.05%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		417,234		$ 13,412,842				$ 32.15	33.05%
	Other Firm (1)		99,419	N/A	3,018,871	N/A	N/A	N/A	$ 30.37	7.88%
	Other Non-Firm (2)		173,528	N/A	(1,604,654)	N/A	N/A	N/A	(9.25)	13.75%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		272,947		$ 1,414,217				$ 5.18	21.63%
	TOTAL PURCHASES		690,181		$ 14,827,059				$ 21.48	54.68%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,262,274		$ 35,179,973				$ 27.87	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,190,009							94.28%
	Sales for Resale	-	71,345							5.65%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0.00%
	Electric Dept. Only		1,366							0.11%
	TOTAL @ THE METER		1,262,720							100.04%
	Total Energy Losses		(446)							-0.04%
	Percent Losses									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	100	1,005	$ 30,883	N/A	10.051	$ 30.727	$ 308.83	0.01%
	Nelson 6	385.0	132	1,450	26,054	N/A	10.984	17.970	197.38	0.01%
	Sabine	1,890.0	-	-	-	N/A	-	-	-	0.00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		232	2,455	$ 56,937		10.582	$ 23.193	$ 245.42	0.02%

Utilities Notes:

1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month.

CAPACITY CONTRACT	Expiration Dates
CONOCOPHILIPS-SRW	May 31, 2013
NRG POWER PARTNERS	February 28, 2012

2) Other Non-Firm Purchases are net of off-system sales: 296,757 mWh
$ 12,163,887

Control Number: 39036

Item Number: 135

Addendum StartPage: 0

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL COST REPORT
FOR THE MONTH OF DECEMBER 2011

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Current System Fuel Factor: (1)

	ACCOUNT	RECONCILABLE	NON-RECONCILABLE	TOTAL
TOTAL SYSTEM FUEL/PURCHASED POWER COSTS:				
Fuel Cost	501	$ 20,869,329	$ 134,774	$ 21,004,103
Allowances	509	$ 1,727	$ -	$ 1,727
Purchased Power Cost - Nuclear	555	1,584,090	10,044,607	11,628,697
Purchased Power Cost - Non-Nuclear	555	34,998,230	11,588,595	46,586,825
TOTAL SYSTEM COST:		$ 57,453,376	$ 21,767,976	$ 79,221,352
Gains from Disposition of Allowances	411	$ -	$ -	$ -
(2) Sales for Resale Revenue	447	16,918,436	6,089,595	23,008,031
NET SYSTEM COST:		$ 40,534,940	$ 15,678,381	$ 56,213,321
Texas Fixed Fuel Factor Allocator		94.955%	94.955%	94.955%
	447/555	-	-	-
TEXAS FIXED FUEL FACTOR FUEL/PURCHASED POWER COST:		$ 38,489,952	$ 14,887,407	$ 53,377,359

	ACCOUNT	REVENUES	MWH SALES
TEXAS FIXED FUEL FACTOR RELATED REVENUES:			
Residential	440	$ 16,239,725	389,762
Commercial & Industrial	442	30,525,142	760,934
Street & Highway	444	288,871	6,933
Public Authorities	445	810,195	19,753
Interdepartmental	448	-	N/A
TOTAL TEXAS FIXED FUEL FACTOR RELATED REVENUES		$ 47,863,933	1,177,382

	ACCOUNT	OVER/(UNDER) RECOVERY	INTEREST	TOTAL
OVER/(UNDER) RECOVERY OF COSTS:				
Annual Interest Compound Rate (%):			0.28%	
Beginning Cumulative Balance	182	66,501,460	(10,646,039)	55,855,421
Entry This Month	182	9,373,981	13,016	9,386,997
	182			-
	182			-
	182			-
Ending Cumulative Balance	182	$ 75,875,441	$ (10,633,023)	$ 65,242,418

Comments:

(1) The Texas retail fixed fuel factor is 4.02739 cents/kWh effective with September 2011 billing cycles.

(2) Wholesale fuel clause rates are set by FERC, not applicable to Texas Retail Only off-system sales to other utilities are addressed here, which reduces the total reconcilable and unreconcilable fuel and purchased power costs.

135

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL PURCHASE REPORT
FOR THE MONTH OF DECEMBER 2011

SUPPLIER NAME:	FUEL TYPE	PURCHASE TYPE	Exp. Date (A)	PLANT NAME	MMBTU	COST	$/MMBTU	TONS	TOTAL $/TON	BTU/LB
Triton (Buckskin)	Coal	Firm		Big Cajun No. 2	2,625,302	$ 6,039,862	$ 2.301	155,638	$ 38.807	8,434.0
Macrol Oil	Igniter Fuel	Firm		Big Cajun No. 2	(1,646)	(36,265)	22.032	N/A	N/A	N/A
Coal Sales LLC	Coal	Firm		Nelson 6	3,974,027	10,568,381	2.659	227,355	46.484	8,739.7
SunCoast Products	Igniter Fuel	Firm		Nelson 6	-	-	N/A	N/A	N/A	N/A
Prior Period Adjustments	Coal	N/A	N/A	N/A	22,332	(369,848)	-	-	-	-
Prior Period Adjustments	Igniter Fuel	N/A	N/A	N/A	-	-	-	-	-	-
				TOTAL COAL:	6,620,015	$ 16,202,130	$ 2.447	382,993	$ 42.304	8,642.5
CITIGROUP	NG	SPOT		Sabine	30,000	$ 96,707	$ 3.224			
DCP MIDSTREAM	NG	SPOT		Sabine	960,000	3,262,164	3.398			
ENBRIDGE	NG	SPOT		Sabine	2,248,067	7,524,071	3.347			
JP MORGAN VNTRS	NG	SPOT		Sabine	90,000	298,472	3 316			
KMTEJAS	NG	SPOT		Sabine	620,000	2,107,880	3.400			
NJR	NG	SPOT		Sabine	30,000	101,007	3.367			
SEQUENT	NG	SPOT		Sabine	145,000	484,059	3.338			
	NG	SPOT		Sabine			-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	NG	SPOT		Sabine	-	-	-			
	Oil	SPOT		Sabine	-	-	-			
				Sabine	-	-	-			
Prior Period Adjustments	NG	N/A		Sabine	24,366	(141,067)	-			
Prior Period Adjustments	Oil	N/A		Sabine	-	-	-			
				TOTAL PLANT:	4,147,433	$ 13,733,293	$ 3.311			
BGEM	NG	SPOT		Lewis Creek	310,000	$ 1,029,200	$ 3.320			
CITIGROUP	NG	SPOT		Lewis Creek	30,000	90,792	3 026			
CONOCO	NG	SPOT		Lewis Creek	49,239	161,668	3.283			
ENBRIDGE	NG	SPOT		Lewis Creek	335,000	1,142,250	3.410			
JP MORGAN VNTRS	NG	SPOT		Lewis Creek	5,000	15,307	3.061			
NJR	NG	SPOT		Lewis Creek	20,000	61,053	3.053			
SEQUENT	NG	SPOT		Lewis Creek	190,000	647,616	3.409			
SW ENERGY	NG	SPOT		Lewis Creek	65,000	217,075	3.340			
TETCO	NG	SPOT		Lewis Creek	-	118,626				
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	NG	SPOT		Lewis Creek	-	-	-			
	Oil	SPOT		Lewis Creek	-	-	-			
Prior Period Adjustments	NG	N/A		Lewis Creek	14,192	53,780	-			
Prior Period Adjustments	Oil	N/A		Lewis Creek	-	-	-			
				TOTAL PLANT:	1,018,431	$ 3,537,367	$ 3.473			
				TOTAL NATURAL GAS & OIL	5,165,864	$ 17,270,660	$ 3.343			

Comments: (A) The expiration date of the "firm" gas and coal contracts are shown only if they are within twenty-four (24) months of the reporting month.

PROJECT NO. 39036

ENTERGY TEXAS, INC.
FUEL EFFICIENCY REPORT
FOR THE MONTH OF DECEMBER 2011

Time Period: 744 Hours

	PLANT/SOURCE	NDC MW	MWH	MMBTU	Cost	% CF	HR	$/MMBTU	$/MWH	% MIX
COAL/OIL:	Nelson 6	385.0	79,608	928,380	$ 2,493,502	27.79%	11.662	$ 2.686	$ 31.32	5.73%
	Big Cajun No. 2 Unit 3	227.0	58,665	591,094	1,219,336	34.74%	10.076	2.063	20.78	4.22%
	Prior Period Adjustments		-	-	-	-	-	-	-	0.00%
	TOTAL COAL/OIL	612.0	138,273	1,519,474	$ 3,712,838	30.37%	10.989	$ 2.444	$ 26.85	9.94%
GAS/OIL:	Lewis Creek	520.0	74,622	1,004,239	$ 3,483,587	19.29%	13.458	$ 3.469	$ 46.68	5.37%
	Sabine	1,890.0	358,256	4,088,406	13,769,445	25.48%	11.412	3.368	38.43	25.77%
	Prior Period Adjustments		-	36,139	(96,541)	-	-	-	-	0.00%
	TOTAL GAS/OIL	2,410.0	432,878	5,128,784	$ 17,156,491	24.14%	11.848	$ 3.345	$ 39.63	31.13%
EMISSIONS	509 & 411	-	-	-	1,727	-	-	-	-	0.00%
& GAINS		-	-	-	-	-	-	-	-	0.00%
		-	-	-	-	-	-	-	-	0.00%
	TOTAL EMISSIONS	-	-	-	$ 1,727	-	-	$ -	$ -	
	TOTAL NET GENERATION	3,022.0	571,151	6,648,258	$ 20,871,056	25.40%	11.640	$ 3.139	$ 36.54	41.08%
PURCHASES:	Firm Cogen:		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Non-Firm Cogen		521,228	N/A	15,983,238	N/A	N/A	N/A	30 66	37 49%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL COGEN		521,228		$ 15,983,238				$ 30.66	37.49%
	Other Firm (1)		291,276	N/A	11,118,495	N/A	N/A	N/A	$ 38.17	20.95%
	Other Non-Firm (2)		6,827	N/A	(7,437,849)	N/A	N/A	N/A	(1,089.48)	0.49%
	Prior Period Adjustments		-	N/A	-	N/A	N/A	N/A	-	0.00%
	TOTAL OTHER		298,103		$ 3,680,646				$ 12.35	21.44%
	TOTAL PURCHASES		819,331		$ 19,663,884				$ 24.00	58.92%
	Net Interchange		-	N/A	$ -	N/A	N/A	N/A	$ -	0.00%
	Net Transmission (Wheeling)		-	N/A	-	N/A	N/A	N/A	-	0.00%
	SYSTEM TOTAL AT THE SOURCE		1,390,482		$ 40,534,940				$ 29.15	100.00%
DISPOSITION OF ENERGY:										
	Sales to Ultimate Consumer		1,183,485							85 11%
	Sales for Resale	-	63,887							4.59%
	Energy Furnished Without Charge									0.00%
	Energy Used by Utility									0 00%
	Electric Dept. Only		1,426							0 10%
	TOTAL @ THE METER		1,248,798							89.80%
	Total Energy Losses		141,684							10.20%
	Percent Losses									
FUEL OIL: (Included in the above generation)										
	Big Cajun No. 2 Unit 3	227.0	(126)	(1,265)	$ (32,674)	N/A	-	$ 25.826	$ 259.32	-0.01%
	Nelson 6	385.0	104	1,218	21,882	N/A	11.708	17.971	210.40	0.01%
	Sabine	1,890.0	-	-	-	N/A	-	-	-	0 00%
	Prior Period Adjustments		-	-	-	N/A	-	-	-	0.00%
	TOTAL OIL		(22)	(48)	$ (10,792)		2.159	$ 227.200	$ 490.55	0.00%

Utilities Notes:

(1) The expiration dates of the "firm" purchased power contracts are shown below if they are within twenty-four (24) months of the reporting month

CAPACITY CONTRACT	**Expiration Dates**
CONOCOPHILIPS-SRW	May 31, 2013
NRG POWER PARTNERS	February 28, 2012

(2) Other Non-Firm Purchases are net of off-system sales: 416,556 mWh
$ 16,918,436

Alternative Turbine Specification Sheet

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- full range of extended scope solutions for power producers and users
- power plants
- lifetime service and support packages

Industrial gas turbines

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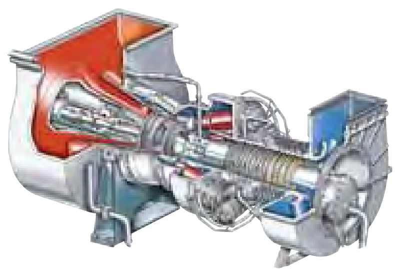
SGT-100

Power generation 5.40MW(e)
- Fuel: Natural gas*
- Frequency: 50/60Hz
- Electrical efficiency: 31.0%
- Heat rate: 11,613kJ/kWh (11,008Btu/kWh)
- Turbine speed: 17,384rpm
- Compressor pressure ratio: 15.6:1
- Exhaust gas flow: 20.6kg/s (45.4lb/s)
- Exhaust temperature: 531°C (988°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 25ppmV

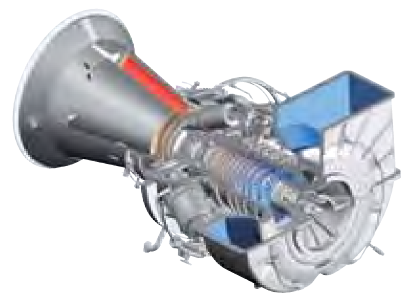
Mechanical drive 5.70MW (7,640bhp)
- Fuel: Natural gas*
- Efficiency: 32.9%
- Heat rate: 10,948kJ/kWh (7,738Btu/bhph)
- Turbine speed: 13,000rpm
- Compressor pressure ratio: 14.9:1
- Exhaust gas flow: 19.7kg/s (43.4lb/s)
- Exhaust temperature: 543°C (1,009°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 25ppmV



SGT-200

Power generation 6.75MW(e)
- Fuel: Natural gas*
- Frequency: 50/60Hz
- Electrical efficiency: 31.5%
- Heat rate: 11,418kJ/kWh (10,823Btu/kWh)
- Turbine speed: 11,053rpm
- Compressor pressure ratio: 12.2:1
- Exhaust gas flow: 29.3kg/s (64.5lb/s)
- Exhaust temperature: 466°C (871°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 25ppmV

Mechanical drive 7.68MW (10,300bhp)
- Fuel: Natural gas*
- Efficiency: 33.0%
- Heat rate: 10,906kJ/kWh (7,708Btu/bhph)
- Turbine speed: 10,950rpm
- Compressor pressure ratio: 12.3:1
- Exhaust gas flow: 29.5kg/s (65.0lb/s)
- Exhaust temperature: 489°C (912°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 15ppmV



SGT-300

Power generation 7.90MW(e)
- Fuel: Natural gas*
- Frequency: 50/60Hz
- Electrical efficiency: 30.6%
- Heat rate: 11,773kJ/kWh (11,158Btu/kWh)
- Turbine speed: 14,010rpm
- Compressor pressure ratio: 13.7:1
- Exhaust gas flow: 30.2kg/s (66.6lb/s)
- Exhaust temperature: 542°C (1,008°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 15ppmV

Mechanical drive 8.2MW (11,000bhp)
- Fuel: Natural gas*
- Efficiency: 34.6%
- Heat rate: 10,400kJ/kWh (7,350 Btu/bhph)
- Turbine speed: 11,500rpm
- Compressor pressure ratio: 13.3:1
- Exhaust gas flow: 29.0kg/s (63.9lb/s)
- Exhaust temperature: 498°C (928°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 15ppmV

**No intake or exhaust loss; other gaseous, liquid and/or dual fuel options available*

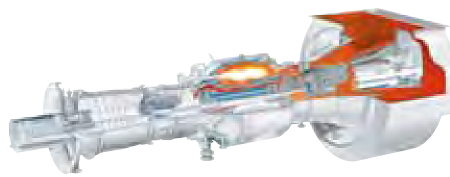
SGT-400

Power generation 12.90MW(e)
- Fuel: Natural gas*
- Frequency: 50/60Hz
- Electrical efficiency: 34.8%
- Heat rate: 10,355kJ/kWh (9,815Btu/kWh)
- Turbine speed: 9,500rpm
- Compressor pressure ratio: 16.8:1
- Exhaust gas flow: 39.4kg/s (86.8lb/s)
- Exhaust temperature: 555°C (1,031°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 15ppmV

Also available as 14.40MW(e)

Mechanical drive 13.40MW (18,000bhp)
- Fuel: Natural gas*
- Efficiency: 36.2%
- Heat rate: 9,943kJ/kWh (7,028Btu/bhph)
- Turbine speed: 9,500rpm
- Compressor pressure ratio: 16.8:1
- Exhaust gas flow: 39.4kg/s (86.8lb/s)
- Exhaust temperature: 555°C (1,031°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 15ppmV

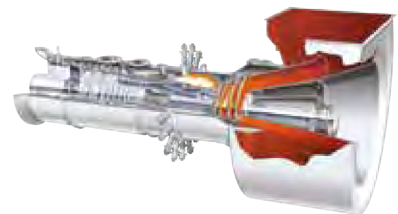
Also available as 15.00MW (20,100bhp)



SGT-500

Power generation 19.10MW(e)
- Fuel: Natural gas*
- Frequency: 50/60Hz
- Electrical efficiency: 33.8%
- Heat rate: 10,664kJ/kWh (10,107Btu/kWh)
- Turbine speed: 3,600rpm
- Compressor pressure ratio: 13:1
- Exhaust gas flow: 97.9kg/s (215.9lb/s)
- Exhaust temperature: 369°C (697°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 42ppmV

Mechanical drive 19.52MW (26,177bhp)
- Fuel: Natural gas*
- Efficiency: 34.5%
- Heat rate: 10,432kJ/kWh (7,373Btu/bhph)
- Turbine speed: 3,450rpm
- Compressor pressure ratio: 13:1
- Exhaust gas flow: 97.9kg/s (215.9lb/s)
- Exhaust temperature: 369°C (697°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 42ppmV

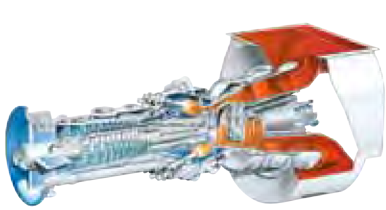


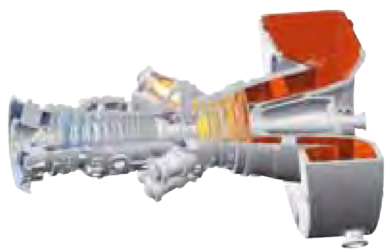
SGT-600

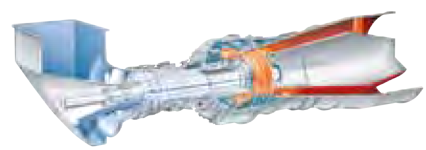
Power generation 24.77MW(e)
- Fuel: Natural gas*
- Frequency: 50/60Hz
- Electrical efficiency: 34.2%
- Heat rate: 10,533kJ/kWh (9,983Btu/kWh)
- Turbine speed: 7,700rpm
- Compressor pressure ratio: 14:1
- Exhaust gas flow: 80.4kg/s (177.3lb/s)
- Exhaust temperature: 543°C (1,009°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 25ppmV

Mechanical drive 25.40MW (34,100bhp)
- Fuel: Natural gas*
- Efficiency: 35.1%
- Heat rate: 10,258kJ/kWh (7,250Btu/bhph)
- Turbine speed: 7,700rpm
- Compressor pressure ratio: 14:1
- Exhaust gas flow: 80.4kg/s (177.3lb/s)
- Exhaust temperature: 543°C (1,009°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 25ppmV

**No intake or exhaust loss; other gaseous, liquid and/or dual fuel options available*







SGT-700

Power generation 31.21MW(e)
- Fuel: Natural gas*
- Frequency: 50/60Hz
- Electrical efficiency: 36.4%
- Heat rate: 9,882kJ/kWh (9,367Btu/kWh)
- Turbine speed: 6,500rpm
- Compressor pressure ratio: 18.6:1
- Exhaust gas flow: 94kg/s (208lb/s)
- Exhaust temperature: 528°C (983°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 15ppmV

Mechanical drive 32.04MW (42,966bhp)
- Fuel: Natural gas*
- Efficiency: 37.4%
- Heat rate: 9,629kJ/kWh (6,806Btu/bhph)
- Turbine speed: 6,500rpm
- Compressor pressure ratio: 18.6:1
- Exhaust gas flow: 94kg/s (207lb/s)
- Exhaust temperature: 528°C (983°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 15ppmV

SGT-750

Power generation 35.93MW(e)
- Fuel: Natural gas*
- Frequency: 50/60Hz
- Electrical efficiency: 38.7%
- Heat rate: 9,296kJ/kWh (8,811Btu/kWh)
- Turbine speed: 6,100rpm
- Compressor pressure ratio: 23.8:1
- Exhaust gas flow: 113.3kg/s (249.8lb/s)
- Exhaust temperature: 462°C (864°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 15ppmV

Mechanical drive 37.11MW (49,765bhp)
- Fuel: Natural gas*
- Efficiency: 40.0%
- Heat rate: 9,002kJ/kWh (6,362Btu/bhph)
- Turbine speed: 3,050 – 6,405rpm
- Compressor pressure ratio: 23.8:1
- Exhaust gas flow: 113.3kg/s (249.8lb/s
- Exhaust temperature: 462°C (864°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 15ppmV

SGT-800

Power generation 47.00MW(e)
- Fuel: Natural gas*
- Frequency: 50/60Hz
- Electrical efficiency: 37.5%
- Heat rate: 9,597kJ/kWh (9,096Btu/kWh)
- Turbine speed: 6,608rpm
- Compressor pressure ratio: 19:1
- Exhaust gas flow: 131.5kg/s (289.9lb/s)
- Exhaust temperature: 544°C (1,011°F)
- NO_x emissions (with DLE, corrected to 15% O_2 dry): ≤ 15ppmV

Also available as 50.50MW(e)

**No intake or exhaust loss; other gaseous, liquid and/or dual fuel options available*

Wingas compressor station, Eischleben, Germany: Two Siemens compressor trains, each powered by a 30MW SGT-700 gas turbine, boosting the pipeline pressure for Natural gas* transport.

Siemens gas turbine package: A 5.25MW(e) industrial gas turbine cogeneration package, including an SGT-100 gas turbine, generator and auxiliaries, providing heat and power.

Göteborg Energi AB, Rya, Gothenburg: Three 45MW(e) SGT-800 gas turbines at the combined heat and power plant provide electricity and heating to the city of Gothenburg.

Sasol Technology (Pty) Ltd, South Africa: The 13.4MW SGT-400 gas turbine is the key component to the two pipeline compressor sets installed at the Komatipoort compressor station.

Power generation and industrial applications

Independent power producers, utilities and municipalities:

- Simple cycle and combined cycle power plants for base load, standby power and peak lopping
- Cogeneration for industrial plants with high heat load and district heating schemes

Power users:

- Chemical plants and pharmaceuticals
- Food and beverage plants
- Automotive plants, mining, heavy industry
- Pulp and paper, textiles
- Hospitals, universities and other building complexes
- Marine propulsion, other process and manufacturing industries

Oil and gas industry

Upstream – onshore and offshore production, fixed and floating:

- Prime movers for water injection and crude oil pumping, gas lift, gas/oil separation
- Well depletion/wellhead boosting, natural gas and sour gas injection
- Gas gathering and export gas compression, refrigeration compression for gas-processing plant
- Power generation and power supply

Midstream – pipelines, storage and LNG:

- Gas turbine driven compressors and pumps, e.g. for high-pressure gas transmission pipelines and oil pumping
- Power generation and refrigerant compression for liquefied Natural gas* (LNG)

Downstream – refineries, petrochemicals, GTL:

- Gas to liquids (GTL) – power generation
- Refinery – power generation

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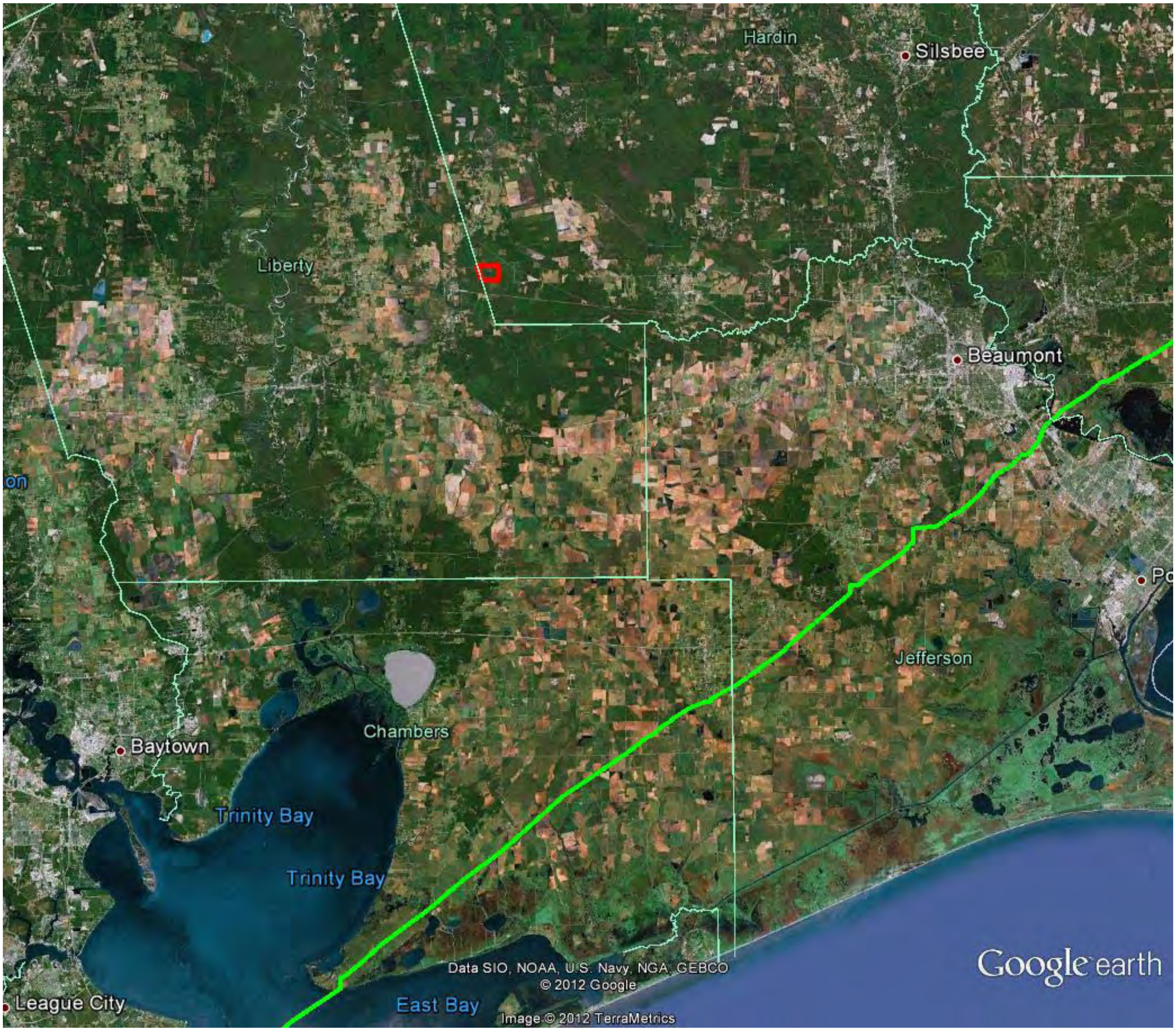
Denbury Green Pipeline Map



Google earth

miles 30
km 50

Good Combustion Practices

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

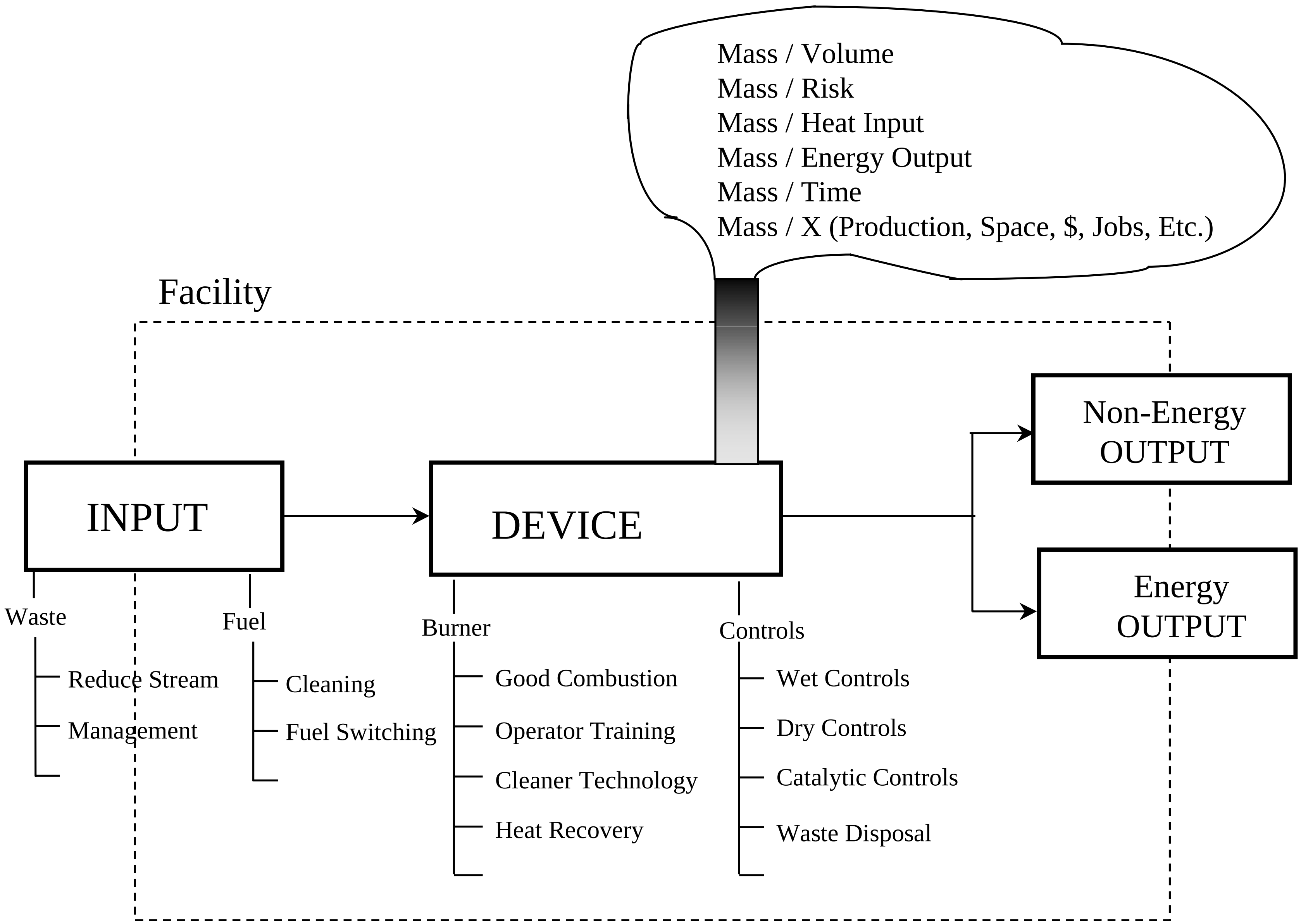
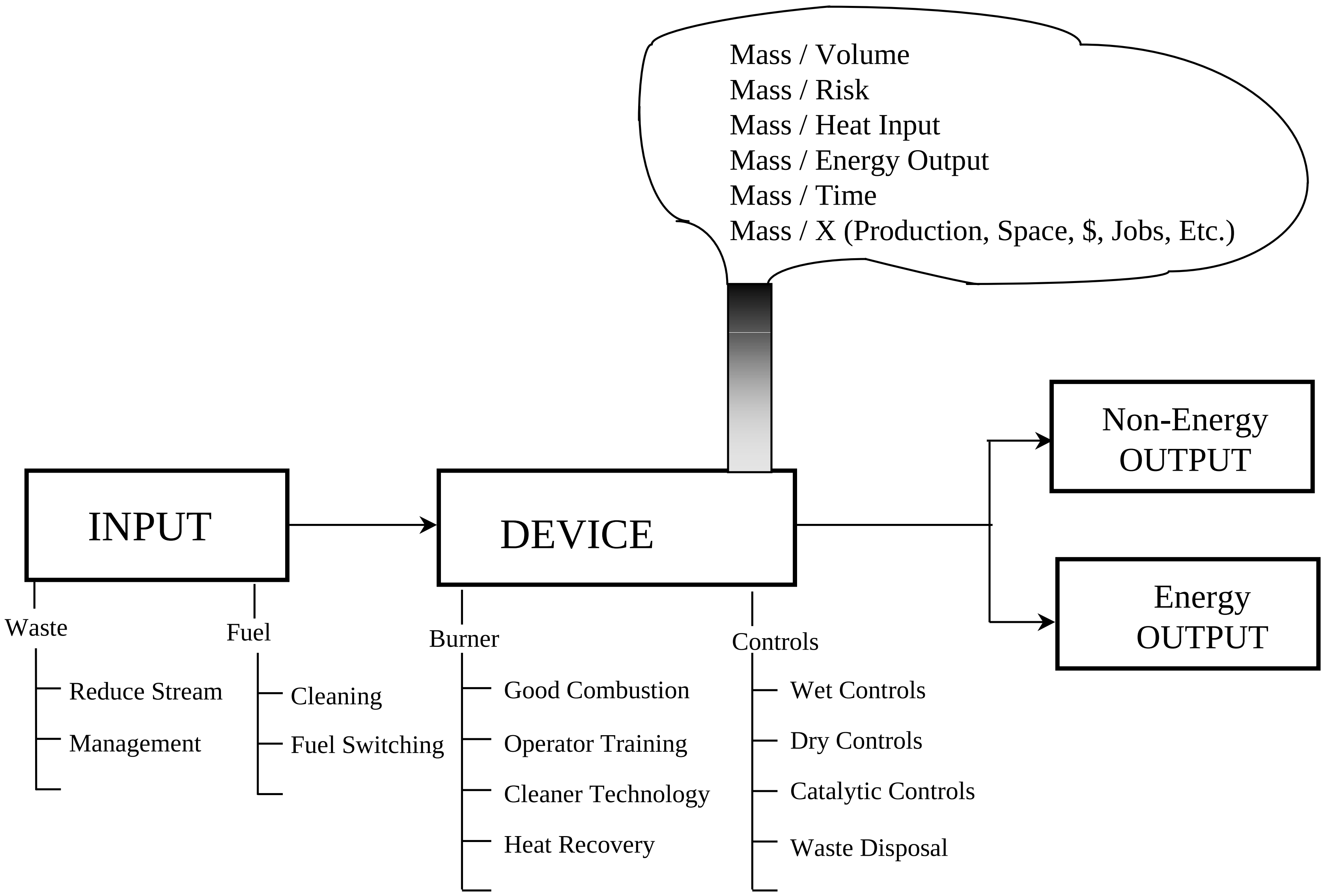

Mass / Volume
Mass / Risk
Mass / Heat Input
Mass / Energy Output
Mass / Time
Mass / X (Production, Space, $, Jobs, Etc.)
Facility
INPUT
DEVICE
Non-Energy OUTPUT
Energy OUTPUT
Waste
Reduce Stream
Management
Fuel
Cleaning
Fuel Switching
Burner
Good Combustion
Operator Training
Cleaner Technology
Heat Recovery
Controls
Wet Controls
Dry Controls
Catalytic Controls
Waste Disposal

FIGURE 1


Mass / Volume
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Wet Controls
Dry Controls
Catalytic Controls
Waste Disposal

FIGURE 2

TCEQ Fugitive Guidance

October 2000
Draft

Air Permit Technical Guidance for Chemical Sources:

Equipment Leak Fugitives

Air Permits Division

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

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TECHNICAL DISCLAIMER

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References to abatement technologies are not intended to represent minimum or maximum levels of BACT. Determinations of BACT are made on a case by case basis as part of the New Source Review of permit applications. BACT determinations are always subject to adjustment in consideration of specific process requirements, air quality concerns, and recent developments in abatement technology. Additionally, specific health effects concerns may indicate stricter abatement than required by the BACT determination.

The represented calculation methods are intended as an aid in the completion of an acceptable submittal; alternative calculation methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data.

The enclosed regulations are applicable as of the publication date of this package, but are subject to revision during the application preparation and review period. It is the responsibility of applicants to remain abreast of regulation developments which may affect their industries.

The special conditions included in this package are for purposes of example only. Special conditions included in an actual permit are written by the reviewing engineer to address specific permit requirements and operating conditions.

The electronic version of this document may or may not contain attachments or forms (such as the PI-1, Standard Exemptions, or Tables) that can be obtained electronically elsewhere on the TCEQ Internet site.

EQUIPMENT LEAK FUGITIVES

This document is intended to aid the permit applicant in the preparation of a technically complete permit application. The fugitive emissions discussed in this standardization package refer to the emissions from piping components and associated equipment including valves, connectors, pumps, compressor seals, relief valves, sampling connections, process drains, and open-ended lines. Uncaptured emissions emanating from other sources such as cooling towers, oil/water separators, material stockpiles, and loading operations are not addressed.

The TCEQ encourages pollution prevention, specifically source reduction, as a means of eliminating or reducing air emissions from industrial processes. The applicant should consider opportunities to prevent or reduce the generation of emissions at the source whenever possible through methods such as product substitutions, process changes, or training. Considering such opportunities prior to designing or applying "end-of-pipe" controls can not only reduce the generation of emissions, but may also provide potential reductions in subsequent control design requirements (e.g., size) and costs.

Table of Contents

I. REGULATIONS GOVERNING VOC EQUIPMENT LEAKS

A number of state and federal regulations exist that address volatile organic compounds (VOC) equipment leaks. All permit applications must demonstrate that a facility will be in compliance with all applicable Rules and Regulations. New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAPS and MACT) and TCEQ 30 TAC Chapter 115 have fugitive emission monitoring programs that vary depending on the specific industry, the material, and the county where the source is located. Each of the major fugitive emission monitoring programs required by state or federal regulation is listed below by industry type. For specific details, refer to the actual regulation in question.

PETROLEUM REFINERIES

30 TAC Chapter 115 (TCEQ Regulation V)

30 TAC § 115.352 Beaumont/Port Arthur, Dallas/Ft. Worth, Houston/Galveston and El Paso Areas

Leak definition of 10,000 ppmv for pump seals and compressors

Leak definition of 500 ppmv for all other components

30 TAC §115.322 Gregg, Nueces and Victoria Counties

Leak definition of 10,000 ppmv for all components

New Source Performance Standards (NSPS) (40 CFR Part 60)

40 CFR Part 60 Subpart GGG - Equipment Leaks of VOC in Petroleum Refineries (*Excluding those Subject to Subparts VV or KKK*)

National Emission Standards for Hazardous Air Pollutants (NESHAPS) (40 CFR Part 61)

Subpart J for benzene

Maximum Allowable Control Technology (MACT) (40 CFR 63)

Subpart CC - Petroleum Refineries

SYNTHETIC ORGANIC CHEMICALS MANUFACTURING INDUSTRY (SOCMI)

30 TAC Chapter 115 (TCEQ Regulation V)

30 TAC § 115.352 Beaumont/Port Arthur, Dallas/Ft. Worth, Houston/Galveston and El Paso Areas

Leak definition of 10,000 ppmv for pump seals and compressors

Leak definition of 500 ppmv for all other components

30 TAC § 115.322 Gregg, Nueces and Victoria Counties

Leak definition of 10,000 ppmv for all components

New Source Performance Standards (NSPS)

40 CFR Part 60 Subpart VV Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

National Emission Standards for Hazardous Air Pollutants (NESHAPS)

Subpart F for vinyl chloride, Subpart J for benzene

Hazardous Organic NESHAPS (HON)

Subpart H - Equipment Leaks

Subpart I - Certain Process Subject to the Negotiated Regulation for Equipment Leaks

NATURAL GAS PROCESSING

30 TAC Chapter 115 (TCEQ Regulation V)

30 TAC § 115.352 Beaumont/Port Arthur, Dallas/Ft. Worth, Houston/Galveston and El Paso Areas

Leak definition of 10,000 ppmv for pump seals and compressors

Leak definition of 500 ppmv for all other components

New Source Performance Standards (40 CFR Part 60)

Subpart KKK Equipment Leaks of VOC from Onshore Natural Gas Processing Plants

(*Excluding those Covered Under Subparts VV or GGG*)

Maximum Allowable Control Technology (MACT) (40 CFR Part 63)

Subpart HH - Oil and Natural Gas Production Facilities

ADDITIONAL REQUIREMENTS

Please note that the regulations listed above are not an exhaustive list. New MACT standards are being proposed and promulgated that may contain LDAR requirements for specific industries. In addition, 30 TAC Chapter 115 may list fugitive emission inspection and monitoring requirements in sections other than those written specifically to address fugitive emissions. For example, fugitive inspection and maintenance requirements for marine terminals and gasoline terminals are contained in Section 115.214 of 30 TAC Chapter 115, Subchapter C, "Volatile Organic Compound Transfer Operations."

II. QUANTIFYING UNCONTROLLED EMISSIONS

Fugitive emission rates are estimates based on leak frequencies found in case studies of chemical plants, oil and gas facilities, refineries and gasoline marketing terminals. An average leak factor is used to determine what the fugitive emission rate is for an area, a facility, or an entire plant. In general, there are five different sets of fugitive emission factors: (1) refinery factors, (2) oil and gas production operations factors, (3) SOCMI factors, (4) petroleum marketing terminal factors, and (5) derived factors used for specific compounds. Within each of the five sets, different factors are used to estimate the uncontrolled emission rates for each specific type of component (connectors, valves, pumps, etc.) and for the type of material in service (light liquid, heavy liquid, or gas/vapor). Each of the leak factors accepted by the TCEQ for use in permit applications is discussed below. The emission factors are provided on Attachment II.

SOCMI FACTORS

The SOCMI factors are generally for use in chemical plants including chemical processes that are located in a refinery. SOCMI factors are divided into three different sets which are applied in different situations.

The original SOCMI average factors were developed to represent fugitive emission rates from all chemical plants. The SOCMI average factors are found in EPA 453/R-95-017, page 2-12. From these factors, the TCEQ further derived two additional sets of factors: “SOCMI with ethylene” to be used for components in service of material which is greater than 85% ethylene, and ”SOCMI without ethylene" to be used where the ethylene concentration is less than 11%. For streams where the ethylene concentration is between 11% - 85%, the SOCMI average factors should be applied.

SOCMI NON-LEAKER FACTORS AND LOW VAPOR PRESSURE COMPOUNDS

Fugitive emissions from components in service where the material has a vapor pressure between 0.147 psia and 0.0147 psia should be estimated with the SOCMI Non-Leaker factors. The SOCMI Non-Leaker factors were developed from test data where no leaking emissions occurred above

10,000 ppmv; therefore, using the Non-Leaker factors assumes that no leaks will occur over the 10,000 ppmv leak detection threshold. For materials with a vapor pressure less than 0.0147 psia, fugitive emissions should be calculated using the SOCMI without ethylene factors with the Audio/Visual/Olfactory (AVO) reduction credits applied. In both cases, a weekly AVO inspection similar to the example condition given in Attachment I(E) will be required in the permit special conditions.

REFINERY FACTORS

Refinery factors are given in the Environmental Protection Agency's (EPA) Compilation of Air Pollutant Emission Factors, AP-42 (4th Edition), or EPA 453/R-95-017, page 2-13. Refinery factors are used when estimating fugitive emissions in a refinery process or production facility. A chemical process, such as a MTBE production unit, may be located in a refining facility but because it is not considered a refinery process, the refinery factors should not be used to calculate that specific unit's fugitive emissions.

PETROLEUM MARKETING TERMINAL FACTORS

In February of 1995 the Air Permits Division approved the use of the Petroleum Marketing Terminal Factors found in EPA document EPA-453/R-95-017, "Protocol for Equipment Leak Emission Estimates." These factors are used to estimate fugitive emissions from components at gasoline distribution facilities that are one-step removed from local gasoline stations and other end-users. Although gasoline distribution facilities may also handle jet fuel and diesel, gasoline is their primary product. Loading racks at chemical plants and refineries may not use these factors. Use of the petroleum terminal factors is accompanied by an AVO LDAR program performed on a monthly basis as specified in a permit special condition similar to the example condition in Attachment I(F). The petroleum marketing terminal factors include the appropriate reduction credit for the AVO inspection; therefore, no additional reductions to the factors are necessary. The decision to require an AVO program instead of an instrument inspection was based on the EPA/API bagging study of various gasoline distribution facilities employing a variety of LDAR programs. The results of the study indicated that little or no improvement in fugitive emission control was achieved when an instrument was used to detect leaks at this type of facility.

OIL AND GAS PRODUCTION OPERATIONS FACTORS

The Oil and Gas Production factors are based on EPA evaluated data on equipment leak emissions from the oil and gas production industry gathered by the American Petroleum Institute (API). There are four different equipment service categories covered by the Oil and Gas Production factors: Gas, Heavy Oil (< 20˚ API gravity), Light Oil (> 20˚ API gravity), and Water/Light Oil (water streams in light oil service with a water content between 50% and 99%). The gas factors estimate total hydrocarbon emissions; therefore, the calculated emission rates must be multiplied by the weight percentage of C3+ compounds in the gas stream to get a total VOC rate for permitting purposes. It is important to note that the Oil and Gas Production Operations gas factors replace the Gas Plant Fugitive Factors from the previous EPA protocol document (EPA-453/R-93-026).

Operators of crude oil pipeline facilities which handle weathered or "dead" crude may use the Oil and Gas Heavy Oil (< 20˚ API gravity) factors to estimate fugitive emissions. This decision was based upon technical demonstrations by the industry that weathered crude is free of the entrained gases and easily volatilized light ends which affected the fugitive emissions factors based upon studies at tank batteries and other upstream facilities.

PHOSGENE, BUTADIENE, AND ETHYLENE OXIDE FACTORS

Specific factors have been developed for use with components in phosgene, butadiene, and ethylene oxide service. These factors are used to estimate fugitive emissions from components in phosgene, butadiene, and ethylene oxide service when monitored with the 28MID Leak Detection and Repair Program at the following leak definitions:

Phosgene 50 ppmv

Butadiene 100 ppmv

Ethylene Oxide   500 ppmv

Note: the EO connector factor does not include instrument monitoring. An additional reduction credit can be taken if connector monitoring is required.

ODOROUS/INORGANIC COMPOUNDS

For odorous or toxic inorganic compounds such as chlorine (Cl_2), ammonia (NH_3), hydrogen sulfide (H_2S), hydrogen fluoride (HF), and hydrogen cyanide (HCN), fugitive emissions are calculated in the same manner as any VOC fugitive emissions according to the type of facility. Although the VOC emission factors were not developed specifically for use with inorganic compounds, they are presently the best tool available for estimating fugitive emissions of inorganics.

The calculated uncontrolled emission rates can be reduced according to the credit allowed by any monitoring program to be implemented at the facility. The emission rates of the inorganic compounds are determined through speciating (see Attachment IV) the calculated total emission rate by multiplying the total emission rate by the weight percent of each individual compound present in the stream. Note that there are no additional monitoring requirements for inorganic compounds if the maximum predicted off-property impact is acceptable. If it is expected that the leakage of these compounds would be detected by smell before an instrument monitoring device would register a leak, see Section III for information on reducing the emission rate of inorganic compounds through a physical inspection program.

LIGHT/HEAVY LIQUIDS

Several of the factors make a distinction between the leak rate for heavy liquids and light liquids. For purposes of choosing an emission factor, heavy liquids are defined as having a vapor pressure of 0.044 psia or less. Light liquids are the liquids with vapor pressures higher than 0.044 psia at 68˚F.

COMPONENTS EXEMPT FROM MONITORING REQUIREMENTS

Emissions from components exempt from monitoring requirements based on size, physical location at a facility, or low vapor pressure *MUST* be calculated and included in the estimated fugitive emission rate regardless of any monitoring exemptions. There are presently no exemptions based on component size in Regulation V for the ozone nonattainment counties as mandated by EPA. In Gregg, Nueces, and Victoria Counties, valves with a nominal size of two inches or less are exempt from monitoring provided that certain requirements are met.

None of the 28 Series Leak Detection and Repair (LDAR) programs requires instrument monitoring of valves less than two inches in diameter; however, if the facility is located in an ozone nonattainment county and is subject to monitoring under 30 TAC 115.352, the two inch exemption will be removed from the permit conditions to be consistent with the regulation. In addition, certain non-accessible components, as defined in 30 TAC Chapter 115, are exempt from monitoring requirements. Monitoring requirements also vary depending on the vapor pressure of the compound. Fugitive emissions from components in heavy liquid service may be exempt from monitoring; however, the uncontrolled emissions must still be estimated.

SCREWED FITTINGS, LIQUID RELIEF VALVES, AND NON-EMITTING SOURCES

Factors have not been developed for certain types of piping components. In order to ensure consistency the TCEQ has designated the factor of a component with similar characteristics to be used to estimate fugitive emissions as follows:

I. Emissions from screwed fittings should be estimated in the same manner as flanges.

II. Emissions from liquid relief valves should be estimated in the same manner as light liquid valves.

III. Emissions from agitators should be estimated in the same manner as light liquid pumps.

Fugitive emissions should not be estimated from the following sources:

1) Tubing size lines (flexible lines ≤ 0.5'' in diameter) and equipment if they are not subject to monitoring by any federal or state regulation

2) Non-piping type fittings (swedgelock or ferrule fittings),
3) Streams where the operating pressure is at least 0.7 psi below ambient pressure,
4) Mixtures in streams where the VOC has an aggregate partial pressure of less than 0.002 psi at 68˚ Fahrenheit.

**Regardless of the guidance given above, if a piping component is required to be monitored by a state or federal regulation, the fugitive emissions from that component must be estimated.

PROCESS DRAINS

Facilities subject to fugitive emission monitoring under 30 TAC §§115.322 and 352 are required to monitor process drains on an annual basis. A 75 percent reduction credit may be applied for annual monitoring of process drains at a leak threshold of 500 ppmv provided the drain is designed in such a manner that repairs to leaking drains can be achieved. For example, flushing a water seal on a leaking process drain would constitute repair, so a 75 percent reduction credit may be applied.

At present, the Refinery Factors are the only set of accepted emission factors that include a factor for fugitive emissions from process drains. This factor may be applied to any process drain regardless of facility or industry type.

HOURS OF OPERATION

Fugitive emission factors are independent of process unit throughput and are assumed to occur if there is material in the line, regardless of the activity of the process. Because fugitive emissions occur when there is material in the line, the hours in service for all streams should always be 8,760 hours annually regardless of process downtime. Any exception to this service time would require a permit condition requiring the lines to be purged during process downtime.

CORRELATION EQUATIONS AND PLANT SPECIFIC FACTORS

The use of various correlation equations developed by EPA for estimating fugitive emissions is not accepted for permitting purposes. Since actual monitoring data is required by the equations, they can be used for estimating actual emissions for emission inventory purposes.

Emission factors developed for individual facilities are also not accepted for permitting purposes. Such factors are the results of individual bagging studies which the TCEQ Air Permits Division does not have the resources to quality assure.

III. FUGITIVE EMISSION REDUCTION OPTIONS

There are two methods by which fugitive emission rates can be reduced: leak detection and repair (LDAR) programs and equipment specification.

LEAK DETECTION AND REPAIR (LDAR) PROGRAMS

Leak detection and repair programs can be differentiated by four key criteria:

1) Leak definition
2) Monitoring frequency
3) Properties of the monitored compounds
4) Requirements for repair

The leak definition is the monitored concentration, defined in ppmv, which identifies a leaking component needing repair.

The second criterion, monitoring frequency, varies depending on the component types and the LDAR program in place. Components typically must be monitored on a quarterly basis; however, some programs allow facilities to skip monitoring periods when the percentage of leaking components is maintained under a specified rate.

The third criterion involves LDAR programs which define the components to be monitored by the vapor pressure of the material in the component and the weight percent of VOC in the stream.

The fourth and final criterion is whether the program repair requirements are directed or non-directed maintenance. A directed maintenance program requires that a gas analyzer be used in conjunction with the repair or maintenance of leaking components to assure that a minimum leak concentration is achieved. If a replacement is required to fix a leaking component, the replaced component should be re-monitored within 15 days. A non-directed maintenance does not require the use of a gas analyzer during repair or maintenance of a leaking component.

40 CFR Part 60, 40 CFR Part 61, MACT and Chapter 115 all have LDAR programs required for specific industries, counties, and materials. Refer to Section I to determine if a facility must meet the requirements of these monitoring and repair programs. Also, remember that a facility may be subject to more than one monitoring program and that meeting the requirements of one program does not exempt a facility from the requirements of another. For example, a chemical plant in Harris County may be subject to the monitoring requirements of Regulation V and also have a permit containing the 28MID LDAR program.

There are five instrument assisted leak detection and repair programs to choose from for permitting purposes: 28M, 28RCT, 28VHP, 28MID and 28LAER. LDAR programs allow emission control credits for instrument monitored components and for the physical (AVO) inspection of connectors. These credits can only be given in cases where the components are actually inspected and for components for which the LDAR program could result in emission reductions. A 30% reduction of fugitive connector emission rates is allowed when a weekly AVO inspection is performed. As mentioned previously, components smaller than two inches not subject to fugitive monitoring by regulation are exempt from monitoring requirements. Instrument monitoring of connectors and components less than two inches can be given a reduction credit consistent with the LDAR program if additional emission reductions are needed or desired. The 28LAER LDAR program is used.

strictly to control fugitive emissions which are part of a non-attainment permit. For facilities which are not subject to a non-attainment permit, the same emission reductions may be attained by implementing the 28MID program in conjunction with the 28CNTA LDAR program for connectors.

In an effort to keep the LDAR programs used as permit special conditions as concise as possible, the procedures to justify delay of repair for a leaking component are not outlined in the 28 series LDAR programs and default to the requirements of 30 TAC Chapter 115. The 28 series LDAR programs also use the 30 TAC Chapter 115 definition for nonaccessible valves.

Each of the five instrument monitoring programs is outlined in Table 1.

Table I
Leak Detection and Repair (LDAR) Program Options

LDAR Program		**28M**	**28 RCT**	**28 VHP**	**28 MID**	**28 LAER**
Leak Definition	Pumps and Compressors	10,000 ppmv	10,000 ppmv	2,000 ppmv	500 ppmv	500 ppmv
	All Other Components	10,000 ppmv	500 ppmv	500 ppmv	500 ppmv	500 ppmv [2]
Applicable Vapor Pressure		> 0.5 psia at 100˚F	> 0.044 psia at 68˚F	> 0.044 psia at 68˚F	> 0.044 psia at 68˚F	> 0.044 psia at 68˚F
Monitoring Frequency		Quarterly	Quarterly	Quarterly	Quarterly	Quarterly [2]
Directed/Nondirected Maintenance		Nondirected	Nondirected	Nondirected	Directed	Directed
Equivalent State/Federal Programs		40CFR Part 60/40 CFR Part 61	30 TAC 115.352 [1]	MACT	N/A	Nonattainment NSR

1) Except in Gregg, Nueces, and Victoria Counties where 28 M applies.
2) Connectors are required to be monitored annually with an instrument under 28LAER.

LOW VAPOR PRESSURE COMPOUNDS

Compounds with low vapor pressures can present a problem with instrument monitoring. No reduction credits are allowed for valves and pumps in heavy liquid service under any of the five 28 Series LDAR programs or 30 TAC 115 as components in heavy liquid service are not required to be monitored. An applicant may propose to monitor these components and take the appropriate reduction credits as noted in Attachment III; however, the applicant must demonstrate that leaking components can be detected by implementing an instrument assisted fugitive monitoring program. For materials with vapor pressures below 0.147 psia, implementing a LDAR program with a 10,000 ppmv leak detection definition could be useless as leaking components may never be detected. For example, a component in heavy liquid service (vapor pressure < 0.044 psia) which is subject to a LDAR program with a leak definition of 10,000 ppmv would have a theoretical-saturation concentration of 0.044/14.7 = 2990 ppmv. Depending on the instrument response factor for the compounds being measured, this concentration may or may not be a measurable quantity; thus, it may not be possible to demonstrate an actual emission reduction via instrumental monitoring. These components would never get any increased maintenance or improved emission rates as a result of a LDAR Program with a 10,000 ppmv leak definition; therefore, these components cannot receive any reduction credit. To reduce these emissions, the applicant would have to commit to a 500 ppmv or 2,000 ppmv leak definition program.

AUDIO/VISUAL/OLFACTORY WALK-THROUGH INSPECTION

If the predicted off-property impact of an inorganic/odorous compound is unacceptable based on a predicted exceedance of an Effects Screening Level (ESL) or a maximum allowable ground level concentration specified in one of the regulations, the applicant will be required to commit to an Audio/Visual/Olfactory (AVO) walk-through inspection similar to the permit condition shown in Attachment I(E). Note that the repair time given in this condition may be extended on a case by case basis.

Inorganic/odorous compound fugitive emission rates controlled through the AVO inspection are determined as follows:

> The total number of components in service of the compound in question should be multiplied by the appropriate "SOCMI without ethylene" emission factor. The AVO reduction credits found in Attachment III should then be applied to the uncontrolled inorganic/odorous compound emission rates.

Please note that the AVO inspection program may only be applied to inorganic compounds for which instrument monitoring is not available. In limited instances the AVO inspection program may be applied to extremely odorous organic compounds, such as mercaptans.

REDUCTION CREDIT FOR ANNUAL AND QUARTERLY CONNECTOR MONITORING

Annual instrument monitoring of connectors at a 500 ppmv leak detection limit may receive a 75 percent reduction credit. This determination is based on information contained in the 1993 EPA document "Protocol for Equipment Leak Fugitives" and the results from a limited amount of monitoring data. The control effectiveness percentages given in the protocol document are based on the type of facility, monitored data, and the corresponding reduction in the percentage of leaking flanges. A lower common denominator was used to establish the appropriate reduction credit as it is preferable to allow a single reduction credit for both chemical facilities and refineries. Thus, the 75 percent reduction credit is suitable for use at both petroleum refineries and SOCMI facilities

where the flanges are monitored annually at 500 ppmv. The 28CNTA LDAR program specifies the monitoring and recordkeeping necessary to receive the 75 percent reduction credit. This program may be used in conjunction with any of the other 28 series LDAR programs.

Quarterly instrument monitoring of connectors at a 500 ppm leak detection limit may receive a 97 percent reduction credit. This credit is equivalent to that received by valves monitored at the same leak detection limit and frequency. Although in theory an applicant could monitor connectors quarterly at a 10,000 ppm leak detection limit with a 75 percent credit, there would be a greater benefit for the cost in moving to a more stringent leak definition for the valves and other components prior to implementing connector monitoring. The 28CNTQ LDAR program specifies the monitoring and recordkeeping necessary to receive the 97 percent reduction credit. This program may be used in conjunction with any of the other 28 series LDAR programs.

EQUIPMENT SPECIFICATION

There are certain options that may be implemented in the design of a facility to prevent fugitive emissions from escaping into the atmosphere. When calculating emission rates, various control credits may be applied to components in service as described below. Also, LDAR program monitoring for identified types of equipment is not required if 100 percent reduction credit is given.

<u>Relief Valves</u>

100% control may be taken if one of the following conditions is met:

1) Route relief valve vents to an operating control device
2) Equip with a rupture disc and pressure sensing device (between the valve and disc) to monitor for disc integrity

Note that for new facilities, BACT guidelines generally require that all relief valves vent to a control device.

<u>Pumps</u>

Certain types of pumps are designed to be "leakless" and as such can be given 100% control. Any of the following designs are accepted as leakless pumps:

1) Canned Pumps
2) Magnetic Drive Pumps
3) Diaphragm Pumps
4) Double mechanical seals and the use of a barrier fluid at a higher pressure than the process
5) Double mechanical seals and venting the barrier fluid seal pot to a control device

<u>Valves</u>

100% control may be taken if one of the following conditions is met:

1) Use of bellows valves with bellows welded to both the bonnet and stem
2) Use of diaphragm-type valves
3) Use of seal-welded, magnetically actuated, packless, hermetically sealed control valves

Connectors

Connectors may receive 100% control credit if the connections are welded together around the circumference of the connection such that the flanges are no longer capable of being disassembled by simply unbolting the flanges.

Compressors

Compressors must be designed with enclosed distance pieces and must have the crankcase venting to a control device to be given 100% control.

Double Mechanical Seals

Any component employing double mechanical seals may be given a 75% credit. If the seals are monitored, then use the appropriate monitoring credit.

DESIGN OPTIONS

There are certain options that may be incorporated into the design of a facility to minimize piping components, improve maintenance and/or reduce susceptibility to leaks. While some of these options may not result in reduction credits for fugitive emissions, they can result in lower maintenance costs and improved performance in some cases.

Overall

1) Design equipment layout to minimize pipe run lengths and associated connectors.
2) Minimize the use of valves and other components.
3) Minimize whenever possible the use of relief valves.
4) Optimize piping and component metallurgy for compatibility with process streams and/or physical environment to reduce corrosion potential.

Pumps

1) Use of pressure transfer to eliminate the need for pumps.
2) Use of submerged pumps which limit the exposure of potential leaks to the atmosphere.

Valves

1) Optimize length of time between leaks by using special packing sets and stringent adherence to packing procedures.
2) Use of on-line direct injection repair equipment.
   Note: This option may introduce an additional potential leak path for the valve if corrosion occurs around the tap.

Connectors

1) Eliminate the use of screwed fittings smaller than 2 inches in diameter.
   Note: BACT for fugitives does not allow the use of screwed connections greater than 2 inches in diameter.
2) Use of new technologies which have been deemed by the TCEQ to be equivalent to flanges.

Compressors

1) Designs with lower leak potentials such as diaphragm compressors.
2) Shaft seal design such as carbon rings, double mechanical seals or buffered seals.

3) Design options such as internal balancing, double inlet or gland eductors.

QUANTIFYING FUGITIVE EMISSION REDUCTIONS

Here are several important points to remember when calculating fugitive emission rates:

1) All components must be accounted for when estimating emission rates regardless of exemptions from monitoring requirements.

2) Taking an emission reduction for monitoring implies that all of those components will be monitored regardless of exemptions.

3) Non-accessible components and other unmonitored components must be clearly identified and separated from monitored components when calculating emission rates.

4) All components given emission reduction credits for monitoring must be capable of having reduced emissions through the monitoring program, i.e., any components represented as being monitored must have sufficient vapor pressure to allow the reduction.

5) Representations of emission reductions in a permit application will result in permit special conditions requiring monitoring for certain components based on the emission estimates.

6) Instrument monitoring of connectors is not required by any of the LDAR programs other than 28 LAER. A 30% reduction can be taken for the required weekly walk-through inspection. For quarterly instrument monitoring of connectors under the 28CNTQ LDAR program, the valve credit corresponding to the appropriate leak definition for the LDAR program may be applied instead of the 30% credit. A 75% credit may be taken for annual connector monitoring at a 500 ppm leak definition in conjunction with the 28CNTA LDAR program. The 28CNT LDAR programs are used in addition to the other 28 series LDAR programs if connector monitoring is required by special circumstances.

7) Emission calculations should include a component count for those components with a 100%

control efficiency with a footnote describing the specific method of control.

IV. INFORMATION NEEDED IN A PERMIT APPLICATION

COMPONENT COUNT, TYPE, AND SERVICE CATEGORY

The estimated fugitive emission rate is solely dependent on the number of components in service; therefore, a specific component count is necessary. The count should be separated into the component type categories, i.e., connector, valve, etc. For each specific component type, the number of components should be divided into the appropriate physical service category: gas, light liquid, heavy liquid, chlorine, etc.

With the separated source totals, an estimation of fugitive emission rates with no LDAR program in place can be made. This estimate is simply the emission factor, based on the specific compound and where it is in service, multiplied by the number of components in that service. As an example, for a valve in VOC light liquid service in a refinery, the factor used is 0.024 (lb/hr)/source; therefore, 10 of these valves will emit a total of 0.24 lb/hr. Annual emissions are determined from the short-term emission rate by assuming 8,760 hours per year of operation. The emission factors used in the calculations should be clearly footnoted to show the source of the factors.

CLAIMING EMISSION REDUCTIONS

Emission reductions claimed either though equipment specification or through any of the TCEQ leak detection and repair programs must be clearly identified. The fugitive emission calculations should show the emission factor, the appropriate reduction credit from Attachment III, and the final emission rate for each component type and, if applicable, from each different process stream. Refer to Attachment IV for a sample calculation.

SPECIATED EMISSIONS BY CHEMICAL

A speciation, or breakdown of the different compounds found in a process line, is necessary if the chemical composition is not 100% pure. The speciation is necessary to determine the off-property impact for each different chemical emitted from a fugitive source.
For example, if a line is 80% toluene and 20% ethylene, the emission rate would need to reflect the

estimated quantity of emissions for each compound. Simply multiplying the emission rate by the weight percent of each compound yields the specific emission rate for that compound. If the weight percent of a particular compound varies from one process stream to another, then the fugitive emission rate for each area should be calculated separately, multiplied by the appropriate weight percent, and then totaled. The permit applicant may also group different streams together and determine the maximum percentage of each compound for that group. When using this method, the percentages may total over 100 percent. The total emission rate of each individual chemical should be shown on the Table 1(a), Emission Source Table, submitted with the permit application.

MODIFICATIONS

When submitting a permit application that involves changes to existing permitted equipment, show the existing component counts and emissions rate, the proposed component counts and emissions rate, and the overall changes. The new and increased emissions will be evaluated as part of the permit review process to determine if any off-property impact concerns exist.

V. BEST AVAILABLE CONTROL TECHNOLOGY GUIDELINES

An integral part of the permitting process is the determination of Best Available Control Technology (BACT) for all new and modified sources. Since fugitive emissions are estimated as a whole for a process unit or area, the addition of new piping components will trigger a BACT review for all of the piping components. Table II provides guidelines for determining BACT for process fugitive emissions when submitting a permit application.

Table II

Best Available Control Technology Guidelines for Fugitive Emissions

Uncontrolled Annual Fugitive Emission Rate	**Best Available Control Technology (BACT)**
< 10 tpy	May Not Require Monitoring †
10 ≤ x < 25 tpy	28M Program †
≥ 25 tpy	28VHP Program

† If subject to TCEQ 30 TAC 115.352, 28RCT applies

It is important to note that the uncontrolled annual emission rate triggers and corresponding LDAR programs given in Table II are guidelines only; a case-by-case review will be performed for all permit applications. Separate applicability determinations must also be made for 30 TAC Chapter 115 (TCEQ Regulation V), 40 CFR Part 60, 40 CFR Part 61 or MACT affected sources. It is important to note that a more stringent program may be requested if it is currently in use at other units at the same plant site. For example, a new unit at a large chemical plant would be expected to implement at least the 28M leak detection and repair program even if the uncontrolled fugitive emissions from the new unit are calculated to be less than 10 tons annually.

In addition to the instrument monitoring requirements, certain components have additional requirements to meet BACT. Open-ended lines are required to be equipped with a cap, plug, blind flange or second valve as BACT. New relief valves are required to vent to a control device as BACT for any potential releases and as a side result any fugitive emissions are also controlled. If instrument monitoring is chosen for existing relief valves, monitoring must be performed quarterly regardless of the accessibility of the relief valves. Additional information on BACT for existing relief valves is contained in "Permit Review of Non-traditional Sources of Air Contaminants" by Alan Pegues, PhD., P.E., 1993.

OFF-PROPERTY IMPACTS REVIEW

The control technology determination is separate from the off-property impacts assessment performed during the permit review process. A more stringent LDAR program (up to 28MID) may be required if the TCEQ Toxicology and Risk Assessment Section determines that the predicted off-property impact of fugitive emissions is unacceptable. If impacts problems still exist with the 28MID LDAR program implemented, the following additional steps may be required:

1) Monitoring of connectors using an organic vapor analyzer as opposed to weekly physical inspections
2) Equipment specifications for leakless operation (See Section III)
3) Applicant developed proposal

SPECIAL CONDITIONS - 28M

Piping, Valves, Connectors, Pumps, and Compressors in Volatile Organic Compounds (VOC) Service - 28M

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.5 psia at 100°F or at maximum process operating temperature if less than 100°F or (2) to piping and valves two inches nominal size and smaller or (3) where the operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined in TCEQ 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring period after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations § 60.485(a) - (b) (40 CFR 60.485[a] - [b]).

G. Except as may be provided for in the special conditions of this permit, all pump and compressor seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. Seal systems that prevent emissions may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure or seals degassing to vent control systems kept in good working order.

Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves, connectors, compressor seals, and pump seals found to be emitting VOC in excess of 10,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Every reasonable effort shall be made to repair a leaking component as specified in this paragraph within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TCEQ Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

I. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

J. Fugitive emission monitoring required by an applicable New Source Performance Standard (NSPS), 40 CFR Part 60, or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS), 40 CFR Part 61, may be used in lieu of Items F through I of this condition.

Compliance with the requirements of this condition does not assure compliance with requirements of NSPS or NESHAPS and does not constitute approval of alternate standards for these regulations.

SPECIAL CONDITIONS - 28RCT

Piping, Valves, Connectors, Pumps, and Compressors in Volatile Organic Compounds (VOC) Service - 28RCT

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure equal to or less than 0.044 psia at 68°F or (2) *** REMOVE IF SUBJECT TO REG. V* to piping and valves two inches nominal size and smaller** or (3) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TCEQ 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations Part 60.485(a) - (b).

Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump and compressor seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump and compressor seals found to be emitting VOC in excess of 10,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired.

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TCEQ Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

J. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

K. Fugitive emission monitoring required by 30 TAC Chapter 115 may be used in lieu of Items F through I of this condition.

Compliance with the requirements of this condition does not assure compliance with requirements of an applicable New Source Performance Standard or an applicable National Emission Standard for Hazardous Air Pollutants and does not constitute approval of alternative standards for these regulations.

SPECIAL CONDITIONS - 28VHP

Piping, Valves, Connectors, Pumps, and Compressors in Volatile Organic Compounds (VOC) Service - 28VHP

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68°F or (2) *** REMOVE IF SUBJECT TO REG. V* to piping and valves two inches nominal size and smaller** or (3) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TCEQ 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations Part 60.485(a) - (b).

Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump and compressor seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump and compressor seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired.

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TCEQ Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

J. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

K. Alternative monitoring frequency schedules of 30 TAC Sections 115.352-115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR 63, Subpart H, may be used in lieu of Items F through G of this condition.

Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard, or an applicable National Emission Standard for Hazardous Air Pollutants and does not constitute approval of alternative standards for these regulations.

<u>Piping, Valves, Connectors, Pumps, and Compressors in (insert compound) Service - Intensive Directed Maintenance - 28MID</u>

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. These conditions shall not apply (1) where the concentration in the stream is less than XX percent by weight or (2) where the volatile organic compounds (VOC) has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68°F or (3) ***REMOVE IF SUBJECT TO REG. V.* to piping and valves two inches nominal size and smaller** or (4) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TCEQ 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer with a directed maintenance program. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations § 60.485(a) - (b).

A directed maintenance program shall consist of the repair and maintenance of components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. All new and replacement pumps and compressors shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These seal systems need not be monitored and may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

All other pump and compressor seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.

H. Damaged or leaking valves, connectors, compressor seals, and pump seals found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TCEQ Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

I. In lieu of the monitoring frequency specified in paragraph F, valves in gas and light liquid service may be monitored on a semiannual basis if the percent of valves leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Valves in gas and light liquid service may be monitored on an annual basis if the percent of valves leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of valves leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

J. The percent of valves leaking used in paragraph I shall be determined using the following formula:

$$(Vl + Vs) \times 100/Vt = Vp$$

Where:

Vl = the number of valves found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Vs = the number of valves for which repair has been delayed and are listed on the facility shutdown log.

Vt = the total number of valves in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor valves.

Vp = the percentage of leaking valves for the monitoring period.

K. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard, or an applicable National Emission Standard for Hazardous Air Pollutants and does not constitute approval of alternative standards for these regulations.

SPECIAL CONDITIONS - 28LAER

<u>Piping, Valves, Connectors, Pumps, Agitators, and Compressors in Volatile Organic Compounds (VOC) Service - Intensive Directed Maintenance - 28LAER</u>

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. With the exception of paragraph N, these conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TCEQ 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through. In addition, all connectors shall be monitored by leak-checking for fugitive emissions at least annually using an approved gas analyzer with a directed maintenance program.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer with a directed maintenance program. Non-accessible valves shall be monitored by leak-checking for fugitive emissions at least annually using an approved gas analyzer with a directed maintenance program. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations § 60.485(a) - (b).

A directed maintenance program shall consist of the repair and maintenance of components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. All new and replacement pumps and compressors shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These seal systems need not be monitored and may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

All other pump, compressor, and agitator seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.

H. Damaged or leaking valves, connectors, agitator seals, compressor seals, and pump seals found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. At the discretion of the TCEQ Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

I. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

J. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard, or an applicable National Emission Standard for Hazardous Air Pollutants and does not constitute approval of alternative standards for these regulations.

K. In lieu of the monitoring frequency specified in paragraph F, valves in gas and light liquid service may be monitored on a semiannual basis if the percent of valves leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Valves in gas and light liquid service may be monitored on an annual basis if the percent of valves leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of valves leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

L. The percent of valves leaking used in paragraph K shall be determined using the following formula:

$$(Vl + Vs) \times 100/Vt = Vp$$

Where:

Vl = the number of valves found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Vs = the number of valves for which repair has been delayed and are listed on the facility shutdown log.

Vt = the total number of valves in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor valves.

Vp = the percentage of leaking valves for the monitoring period.

M. Alternative connector monitoring frequency schedules ("skip options") of 40 Code of Federal Regulations Part 63, Subpart H, National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks, may be used in lieu of the annual connector instrument monitoring required by paragraph E of this permit condition.

N. Any component found to be leaking by physical inspection (i.e., sight, sound, or smell) shall be repaired or monitored with an approved gas analyzer within 15 days to determine whether the component is leaking in excess of 500 ppmv of VOC. If the component is found to be leaking in excess of 500 ppmv of VOC, it shall be subject to the repair and replacement requirements contained in this special condition.

AUDIO, VISUAL AND OLFACTORY (AVO) INSPECTION

<u>Piping, Valves, Pumps, and Compressors in (insert compound) Service</u>

A. Audio, olfactory, and visual checks for <u>(insert compound)</u> leaks within the operating area shall be made every four hours.

B. Immediately, but no later than one hour upon detection of a leak, plant personnel shall take the following actions:

(1) Isolate the leak.

(2) Commence repair or replacement of the leaking component.

(3) Use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

Date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the Texas Commission on Environmental Quality (TCEQ) upon request.

PETROLEUM MARKETING TERMINAL AUDIO, VISUAL, AND OLFACTORY (AVO) INSPECTION

<u>Piping, Valves, Pumps, and Compressors in Petroleum Service</u>

A. Audio, olfactory, and visual checks for petroleum product leaks within the operating area shall be made monthly.

B. Every reasonable effort shall be made to repair or replace a leaking component within 15 days after a leak is found. If the repair or replacement of a leaking component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired or replaced until a scheduled shutdown shall be identified in a list to be made available to representatives of the Texas Commission on Environmental Quality (TCEQ) upon request.

Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the TCEQ upon request.

28 CNTA

In addition to the weekly physical inspection required by Item E of Special Condition XX, all connectors in gas\vapor and light liquid service shall be monitored annually with an approved gas analyzer in accordance with Items F thru J of Special Condition XX. Alternative monitoring frequency schedules ("skip options") of 40 Code of Federal Regulations Part 63, Subpart H, National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks, may be used in lieu of the monitoring frequency required by this permit condition. Compliance with this condition does not assure compliance with requirements of applicable state or federal regulation and does not constitute approval of alternative standards for these regulations.

28CNTQ

A. In addition to the weekly physical inspection required by Item E of Special Condition XX, all accessible connectors in gas\vapor and light liquid service shall be monitored quarterly with an approved gas analyzer in accordance with Items F thru J of Special Condition XX.

B. In lieu of the monitoring frequency specified in paragraph A, connectors may be monitored on a semiannual basis if the percent of connectors leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Connectors may be monitored on an annual basis if the percent of connectors leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of connectors leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

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 equipped with a 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 Connection factor for Non-Leaker. Emission factor is in terms of Pounds per Hour per Sample Taken.

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	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.

Control Efficiencies for TCEQ Leak Detection and Repair Programs

Equipment/Service	28M	28RCT	28VHP	28MID	28LAER	Audio/Visual/Olfactory 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%	75%	97%
Light Liquid [7]	30%	30%	30%	30%	75%	97%
Heavy Liquid	30%	30%	30%	30%	30%	97%
Compressors	75%	75%	85%	95%	95%	95%
Relief Valve (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%

Notes:

1. Audio, visual, and olfactory walk-through inspections are applicable for inorganic/odorous and low vapor pressure compounds referenced in Section II.

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 the 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 10^6 = 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 an applicant decides to monitor their connectors using an organic vapor analyzer (OVA) at the same leak definition as valves, then the applicable valve credit may be used instead of the 30%. If this option is chosen, the company 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 equipped with a cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.

Sample Fugitive Emission Rate Calculations
Chemical Plant Implementing the 28VHP LDAR Program

Component Name	Stream Type	Number of Components	SOCMI w/o C_2 Emission Factors	LDAR Program	Control Efficiency	Controlled Emission Rates	
						Lbs/Hour	Tons/Year
Valves	Gas/Vapor	1,019	0.0089	28VHP	97%	0.27	1.19
Valves	Light Liquid	2,263	0.0035	28VHP	97%	0.24	1.04
Pumps	Light Liquid	14	0.0386	28VHP	85%	0.08	0.36
Connectors	Gas/Vapor	1,435	0.0029	28VHP	97% *	0.12	0.55
Connectors	Light Liquid	3,056	0.0005	28VHP	97% *	0.05	0.20
Compressors	Gas/Vapor	1	0.5027	28VHP	85%	0.08	0.33
Relief Valves	Gas/Vapor	12	0.2293	28VHP	100% †	0.00	0.00
Open-Ended Lines	Gas/Vapor	3	0.0040	28VHP	100% ††	0.00	0.00
Total Fugitive Emission Rates						**0.84**	**3.67**

* Flanges monitored at 500 ppmv; therefore, the valve control credit is applied.

† Relief valves routed to a flare; therefore, 100% control credit is applied.

†† The 28 Series LDAR Programs require open-ended lines to equipped with a cap, blind flange, plug, or a second valve for 100% control credit. The connector count is increased by the number of open-ended lines to account for the credit.

Fugitive Emission Speciation for Sample Calculations

Chemical Name	Weight Percent in Stream	Controlled Fugitive	
		Lbs/Hour	Tons/Year
Propane	4%	0.03	0.15
Benzene	7%	0.06	0.26
Toluene	62%	0.52	2.28
Xylene	8%	0.07	0.29
Ethylbenzene	17%	0.14	0.62
Hydrogen Sulfide *	2%	0.02	0.07
Total VOC	**98%**	**0.82**	**3.60**
Hydrogen Sulfide *	**2%**	**0.02**	**0.07**

* Calculation method assumes that the maximum off-property impact will not exceed ESL or Regulation II limits for H_2S. See Section II, Odorous/Inorganic Compounds, and Section III, Audio/Visual/Olfactory Walk-Through Inspection, for additional information.