NRG Texas Power LLC
1201 Fannin
Houston, Tx 77002

Hand Delivery

May 8. 2014

Mr. Mike Wilson, PE
Director, Air Permits Division, MC-163
Texas Commission on Environmental Quality

c/o Air & Waste Applications Team
Permits Administrative Review Section
Registration, Review and Reporting Division, MC-161
12100 Park 35 Circle
Building F, First Floor, Room 1206
Austin, Texas 78753

RECEIVED - GPDL
AIR PLANNING SEC.
14 MAY 16 PM 6:03

RE: **Application for PSD Air Quality Permit**
Greenhouse Gas Emissions
Peaking Turbines, P.H. Robinson Generating Station
Galveston County, Texas
NRG Texas Power LLC
CN603207218; RN101062826

Mr. Wilson:

NRG Texas Power LLC (NRG Texas) is submitting the attached original and one copy of an application requesting a new federal Prevention of Significant Deterioration (PSD) authorization for greenhouse gas emissions to authorize the installation of gas-fired combustion turbine electric generating units, and associated plant facilities at the existing P.H. Robinson Electric Generating Station (Robinson Station), located in Galveston County, Texas.

We believe this application is complete and we respectfully request that TCEQ staff complete its review of this submittal in an expedited manner. We would be pleased to meet with you or your staff at any time should you have any questions concerning this application. Please contact me at craig.eckberg@nrgenergy.com or (832) 357-5291 with any questions or requests for more information.

Sincerely,

C.R.E.

Craig R. Eckberg
Senior Manager
Environmental Business

Cc: Mr. Jeff Robinson, Chief, Air Permits Section, USEPA Region 6
Mr. Jason Harris, TCEQ Region 12
Director, Pollution Control Division, Galveston County Health District

Application for a
Prevention of Significant Deterioration
Air Quality Permit
For Greenhouse Gas Emissions

NRG Texas Power LLC
P.H. Robinson Station
Bacliff, Galveston County, Texas

nrg

May 2014

DiSorbo
Environmental Consulting Firm
(713) 955-1230
1010 Travis Street, Suite 916
Houston, TX 77002

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Section 1
Introduction

NRG Texas Power LLC (NRG Texas) owns and operates the P.H. Robinson Electric Generating Station (Robinson Station) in Bacliff, Galveston County, Texas. NRG Texas proposes to add 6 simple cycle electric generating units at the Robinson Station to be used for peaking purposes only. The proposed facilities are existing units that will be relocated and installed at the site. The units are General Electric 7B combustion turbines that have been modified to include 7E components. Each of the six units has an ISO rating of 65 MW but is capable of a nominal maximum generation capacity of about 80 MW at an ambient air temperature of 10 °F. The turbines will be fired exclusively with natural gas. The maximum operating rate of each unit will not exceed a 10% annual capacity factor (equivalent to 876 full load hours), averaged over three calendar years, or a 20% capacity factor in any one year. This operating schedule qualifies the units as Acid Rain Peaking Units under 40 CFR §72.2. The annual NO_x and SO_2 emissions will be limited to less than 100 tpy and 25 tpy, respectively, which will allow the units to be certified as Low Mass Emissions (LME) Units under 40 CFR §75.19.

NRG Texas has submitted an application to TCEQ for an air quality permit for this project that includes all applicable state New Source Review (NSR) requirements and Prevention of Significant Deterioration (PSD) review requirements for CO, $PM/PM_{10}/PM_{2.5}$. The project emissions increases exceed the 75,000 tpy PSD applicability threshold for greenhouse gases (GHG). This document constitutes NRG Texas' application for the required GHG PSD permit. The application is organized as follows:

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

Section 2 contains administrative information and completed TCEQ Federal NSR applicability Tables 1F, 2F, and 3F.

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

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

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

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

Appendix A contains GHG emissions calculations for the affected facilities.

Appendix B contains RBLC Database search results.

Appendix C contains the procedure proposed for correction CO_2e lb/MWh to ISO conditions.

Section 2
Application Forms

This section contains the following forms:

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

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

Administrative Information

A. Company or Other Legal Name: NRG Texas Power LLC		
B. Company Official Contact Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): Mr. Craig R. Eckberg		
Title: Senior Manager, Environmental Business		
Mailing Address: 1000 Main St.		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 832 357-5291	Fax No.:	E-mail Address: craig.eckberg@nrg.com
C. Technical Contact Name: Mr. Craig R. Eckberg		
Title: Senior Manager, Environmental Business		
Company Name: NRG Texas Power LLC		
Mailing Address: 1000 Main St.		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 832 357-5291	Fax No.:	E-mail Address: craig.eckberg@nrg.com
D. Facility Location Information:		
Street Address: 5501 Hwy 146		
If no street address, provide clear driving directions to the site in writing:		
City: Bacliff	County: Galveston	ZIP Code: 77518
E. TCEQ Account Identification Number (leave blank if new site or facility): GB-0037-T		
F. TCEQ Customer Reference Number *(leave blank if unknown)*: CN603207218		
G. TCEQ Regulated Entity Number *(leave blank if unknown)*: RN101062826		
H. Site Name: P.H. Robinson Electric Generating Station		
I. Area Name/Type of Facility: Electric Generating Unit		☒ Permanent ☐ Portable
J. Principal Company Product or Business: Electric Services		
K. Principal Standard Industrial Classification Code: 4911		
L. Projected Start of Construction Date: 10/1/2014	Projected Start of Operation Date: 5/1/2015	
SIGNATURE		
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief.		
NAME: Mr. Craig R. Eckberg		
SIGNATURE: C.R.E. *Original Signature Required*		
DATE: 8 May 2014		

TCEQ

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.:	**TBD**	Application Submittal Date:	**May 2014**
Company:	**NRG Texas Power LLC**		
RN:	**101062826**	Facility Location: **5501 Hwy 146**	
City:	**Bacliff**	County: **Galveston**	
Permit Unit I.D.:	**Simple Cycle Peaking Plant**	Permit Name: **P.H. Robinson Peaking Plant**	
Permit Activity: New Source ___ Modification _X_			
Project or Process Description: **Install New Combustion Turbines for Electric Power Generation**			

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS											
	Ozone		CO	PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	H_2S	TRS	Pb	Other[1]
	VOC	NO_x										CO2e
Nonattainment? (yes or no)	Yes	Yes	No	No	No	No	No	No	NA	NA	No	NA
Existing site PTE (tpy)?	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	<100,000
Proposed project emission increases (tpy from 2F)[2]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	570,653
Is the existing site a major source?	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
[3]If not, is the project a major source by itself?	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Significance Level (tpy)	5	5	100	25	15	10	40	40	10	10	0.6	75,000
If site is major, is project increase significant?	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Yes
If netting required, estimated start of construction?								1-Oct-14				
Five years prior to start of construction								1-Oct-09				contemporaneous
Estimated start of operation								1-May-15				period
Net contemporaneous change, including proposed project, from Table 3F. (tpy)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	570,653
FNSR APPLICABLE? (yes or no)												Yes

1 Other PSD pollutants.
2 Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR § 51.166(b)(23).
3 Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR § 51.166(b)(1).

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

	Senior Manager	8 May 2014
Signature	Title	Date

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

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	CO_2e	Permit No.:	TBD
Baseline Period:	NA	Project Name:	Simple Cycle Peaking Plant

	Affected or Modified Facilities[2] FIN	EPN	Facility Name	Permit No.	Actual Emissions[3] (tons/yr)	A Baseline Emissions[4] (tons/yr)	B Proposed Emissions[5] (tons/yr)	Projected Actual Emissions (tons/yr)	Difference (B-A)[6] (tons/yr)	Correction[7] (tons/yr)	Project Increase[8] (tons/yr)
1	PHR1	PHR1	Coimbustion Turbine 1	TBD		0	94,543		94,543	0	94,543
2	PHR2	PHR2	Combustion Turbine 2	TBD		0	94,543		94,543	0	94,543
3	PHR3	PHR3	Combustion Turbine 3	TBD		0	94,543		94,543	0	94,543
4	PHR4	PHR4	Combustion Turbine 4	TBD		0	94,543		94,543	0	94,543
5	PHR5	PHR5	Combustion Turbine 5	TBD		0	94,543		94,543	0	94,543
6	PHR6	PHR6	Combustion Turbine 6	TBD		0	94,543		94,543	0	94,543
7	FGHTR	FGHTR	Fuel Gas Heater	TBC		0	2,716		2,716	0	2,716
8	PHR-SU-SD	PHR-SU-SD	Startup/Shutdown - All Units	TBD		0	8		8	0	8
9	FUG-NGAS	FUG-NGAS	Fugitives	TBD		0	457		457	0	457
10	FUG-MSS	FUG-MSS	Geseous Fuel venting	TBD			188		188		188
11	INS-FS6	INS-FS6	SF6 from Circuit Breakers	TBD		0	26		26	0	26
12						0			0	0	0
13						0			0	0	0
14						0			0	0	0
15						0			0	0	0
16						0			0	0	0
17						0			0	0	0
18									0	0	0
										Page Subtotal[9]:	570,653
										Project Total:	570,653

Table 3F
Project Contemporaneous Changes

Company: **NRG Texas Power LLC**

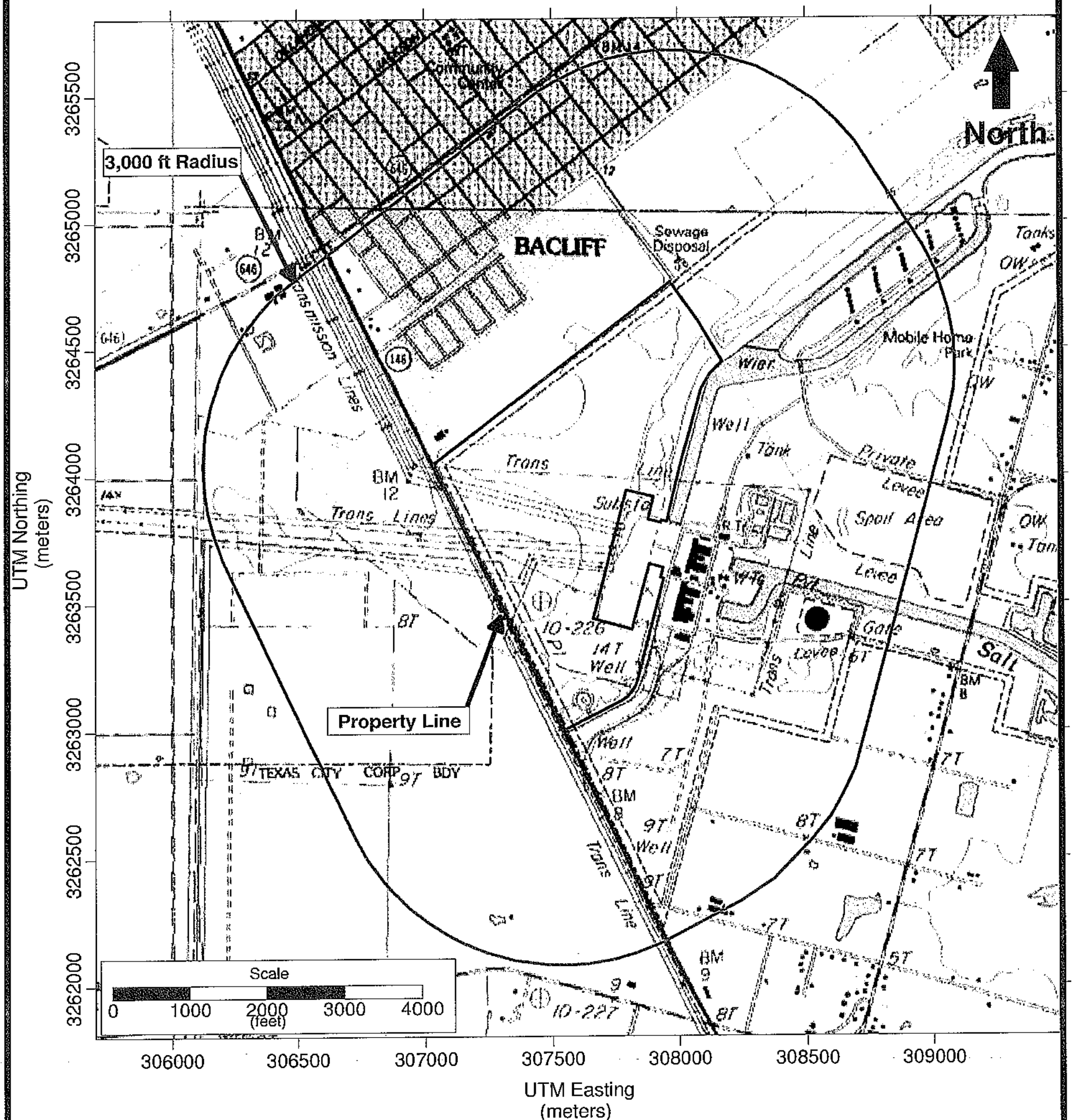
Permit Application No. TBD

Criteria Pollutant: CO_2e

No.	PROJECT DATE	EMISSION UNIT AT WHICH REDUCTION OCCURED		PERMIT NUMBER	PROJECT NAME OR ACTIVITY	A PROPOSED EMISSIONS (tons / year)	B BASELINE EMISSIONS (tons / year)	C DIFFERENCE (A-B) (tons / year)	CREDITABLE DECREASE OR INCREASE (tons / year)
		FIN	EPN						
1	6/1/2014	PHR1	PHR1	TBD	Simple Cycle Peaking Plant	94,543	-	94,543	94,543
2	6/1/2014	PHR2	PHR2	TBD	Simple Cycle Peaking Plant	94,543	-	94,543	94,543
3	6/1/2014	PHR3	PHR3	TBD	Simple Cycle Peaking Plant	94,543	-	94,543	94,543
4	6/1/2014	PHR4	PHR4	TBD	Simple Cycle Peaking Plant	94,543	-	94,543	94,543
5	6/1/2014	PHR5	PHR5	TBD	Simple Cycle Peaking Plant	94,543	-	94,543	94,543
6	6/1/2014	PHR6	PHR6	TBD	Simple Cycle Peaking Plant	94,543	-	94,543	94,543
7	6/1/2014	FGHTR	FGHTR	TBD	Simple Cycle Peaking Plant	2,716	-	2,716	2,716
7	6/1/2014	PHR-SU-SD	PHR-SU-SD	TBD	Simple Cycle Peaking Plant	8	-	8	8
8	6/1/2014	FUG-NGAS	FUG-NGAS	TBD	Simple Cycle Peaking Plant	457		457	457
9	6/1/2014	FUG-MSS	FUG-MSS	TBD	Simple Cycle Peaking Plant	188		188	188
10	6/1/2014	INS-FS6	INS-FS6	TBD	Simple Cycle Peaking Plant	26		26	26
11								0	0
								PAGE SUBTOTAL:	570,653
	Summary of Contemporaneous Changes							TOTAL :	570,653

Section 3
Area Map and Plot Plan

An area map showing the general location of the facility is included as Figure 3-1. Figure 3-2 is a plot plan that shows the layout of the proposed peaking units.

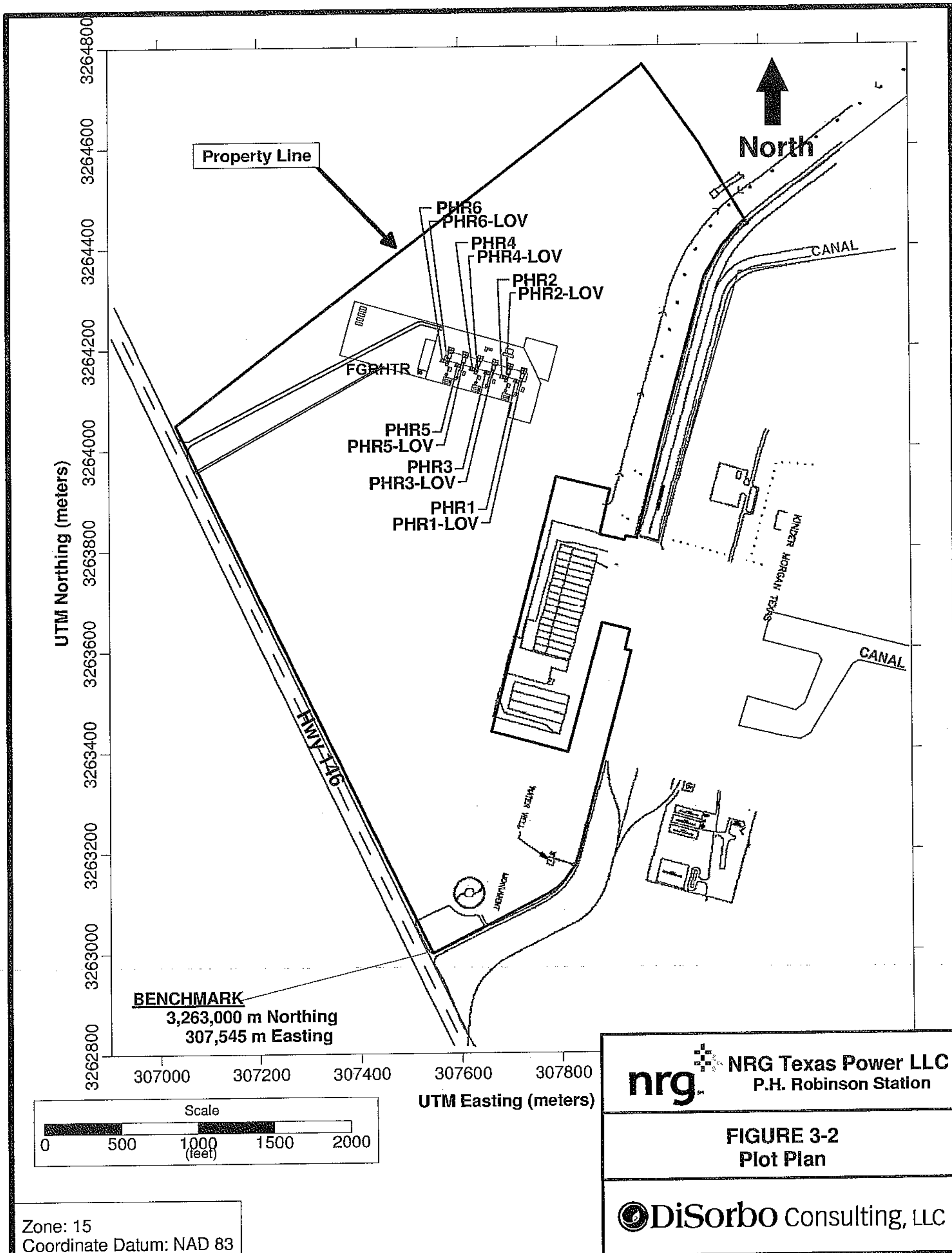


NRG Texas Power LLC
P.H. Robinson Station

FIGURE 3-1
Area Map

DiSorbo Consulting, LLC

Source: mytopo.com/
Zone: 15
Coordinate Datum: NAD 83



nrg NRG Texas Power LLC
P.H. Robinson Station

FIGURE 3-2
Plot Plan

DiSorbo Consulting, LLC

Section 4
Project and Process Description

4.1 Electric Generating Unit

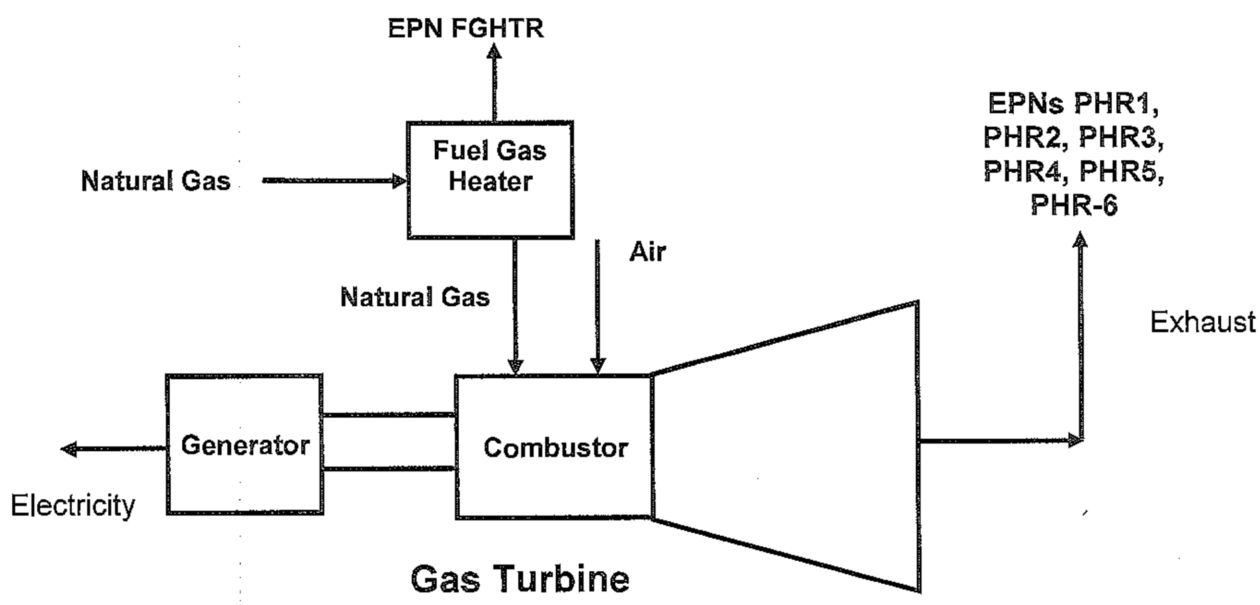
The proposed electric generating facility will consist of six gas turbine-generators (GT) and associated support equipment that will be operated in simple cycle mode to meet peak power demands. A process flow diagram (PFD) for the facility is shown in Figure 4-1. As described in the introduction to this application, the annual capacity factor of each unit will not exceed 10%, averaged over three calendar years, and 20% in any one year. This operating schedule qualifies the turbines as Acid Rain Peaking Units.

4.2 Gas Turbines

Each GT has an ISO rating of 65 MW (at a 27.7% efficiency) but can generate up to a nominal 80 MW of power each at an ambient temperature of 10°F. The exhaust from each GT will be routed directly to the atmosphere at height of 50 ft from grade through a rectangular stack. The turbines will be fired exclusively with pipeline quality natural gas. The proposed gas turbines are currently installed at an existing electric generating station in Mississippi. The turbines are General Electric (GE) units originally manufactured in the 1970s as Frame 7B turbines. In 1998/1999 the turbines were remanufactured and converted to Frame 7E turbines, which include dry low NO_x (DLN) combustor technology. The turbines were put into operation as peakers at the current Mississippi location at that time.

4.3 Fuel Gas Heater

A small natural gas fired heater will be used to pre-heat the fuel prior to entering the turbines. This practice results in a small increase in thermal efficiency.



Note: One of six identical gas turbine units shown

Figure 4-1
NRG Texas Power LLC
P.H. Robinson Station
Process Flow Diagram
Simple Cycle Peaking Plant

Section 5
Emission Rate Basis

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

5.1 Gas Turbines

Maximum annual GHG emission rates were calculated for each turbine. The emission rates are based on 100% load at the lowest expected ambient air temperature (10°F) and 75% relative humidity. Annual emission rates were calculated based on 1,752 hours per year (20% annual capacity factor) at these conditions.

Emissions of CO_2 were calculated by applying the 40 CFR Part 98 Subpart C (a) (3) (i) equation C-1 to the total annual firing rates of the turbines. Emissions of CH_4 and N_2O were calculated using emission factors of 0.001 kg/mmBtu and 0.0001 kg/mmBtu, respectively, from 40 CFR Part 98, Subpart C for natural gas combustion. CO_2e emissions were calculated by multiplying the emission rate of each GHG by the global warming potential factors from the Mandatory Greenhouse Gas Reporting Rules.

During startup of the combustion turbines, emissions of GHGs are not elevated above routine levels; therefore, alternate emission rates were not calculated for these periods. Emissions during startup and shutdown periods will be limited to an average of 8.2 tpy of CO_2e per event, 365-day rolling average, and will be counted toward total emissions in assessing compliance with the proposed annual (tpy) CO_2e emission limits.

5.2 Fuel Gas Heater

Emissions from the fuel gas heater were based on operating at capacity for 30% of the year (2,628 hr/yr). Emissions of CO_2 were calculated by applying the 40 CFR Part 98 Subpart C(a)(3)(i) Equation C-1 to the total annual firing rates of the heater. Emissions of CH_4 and N_2O were calculated using emission factors of 0.001 kg/mmBtu and 0.0001 kg/mmBtu, respectively, from 40 CFR Part 98, Subpart C for natural gas combustion. CO_2e emissions were calculated by multiplying the emission rate of each GHG by the global warming potential factors from the Mandatory Greenhouse Gas Reporting Rules.

5.3 Fugitives

Fugitive emissions of CH_4 originate from the natural gas fuel lines that provide fuel to the combustion turbines. Fugitive emission rates were estimated using the methods outlined in the *TCEQ's Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.* Each fugitive component was classified first by equipment type (valve, pump, relief valve, etc.) and then by material type (gas/vapor, light liquid, heavy liquid). Emission rates were obtained by multiplying the number of fugitive components of a particular equipment/material type by the appropriate SOCMI without ethylene emission factor. No control credit was applied for the natural gas fuel lines although periodic walk through inspections of lines will be made. The methane emission rates for each compound were established by multiplying the total emission rates by the concentration (weight %) of methane in the natural gas, Table A-2. The CH_4 emissions rates were then converted to CO_2e emissions using the global warming potential factor from the Mandatory Greenhouse Gas Reporting Rules.

5.4 MSS Emissions from Gaseous Fuel Venting

Gaseous fuel venting includes, but is not limited to, venting prior to pipeline pigging, venting prior to unit startup, lockout-tag out maintenance, and meter proving to inspect the pipeline integrity or to check the performance of a meter measuring flow or volume throughput. Methane by weight is a major component of the natural gas supply system used by the proposed turbines. The emissions of methane were calculated by multiplying the weight percent of methane in natural gas by the amount of natural gas vented for each type of venting times the expected number of gaseous fuel venting events per year. See Table A-3. The methane emission rates were then converted to CO_2e emissions using the global warming potential factor from the Mandatory Greenhouse Gas Reporting Rules.

5.5 SF_6 Emissions from Electrical Equipment Insulation

Emissions of sulfur hexafluoride (SF_6), Table A-4, due to leaks from the insulation used in new circuit breakers were estimated by applying a 0.5% annual leak rate to the weight of SF_6 estimated to be present in circuit breakers associated with the new facilities.

Table 5-1
Proposed GHG Emissions Limits

EPN	Source Description	CO_2e Emissions (tpy)
PHR1	Combustion Turbine 1	94,543
PHR2	Combustion Turbine 2	94,543
PHR3	Combustion Turbine 3	94,543
PHR4	Combustion Turbine 4	94,543
PHR5	Combustion Turbine 5	94,543
PHR6	Combustion Turbine 6	94,543
FGHTR	Fuel Gas Heater	2,716
FUG	Fugitives	457
MSS-Fug	Gaseous Fuel Venting	188
INS-FS6	SF_6 from Circuit Breakers	26
Total		**570,645**
Startup/Shutdown (tons/event, average)*		
PHR-SU-SD	Startup/Shutdown - All Units	**8.2**

*Startup/Shutdown emissions are per event per turbine. Annual limits for each combustion turbine include emissions during SU/SD events.

Section 6
Best Available Control Technology

PSD regulations require that the best available control technology (BACT) be applied to each new and modified facility that emits an air pollutant for which a significant net emissions increase will occur from the source. The only PSD pollutant addressed in this permit application is GHG. The new emissions units associated with the project that emit GHGs include six natural gas fired combustion turbines, one natural gas fired fuel gas heater, natural gas pipeline fugitives and venting for maintenance purposes, and SF_6 emissions from circuit breakers. This BACT analysis addresses these emission units.

The PSD regulations define BACT at 40 CFR § 52.21(b)(12) as follows:

> [BACT] means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

The PSD regulations do not prescribe a procedure for conducting BACT analyses. Instead, the U.S. EPA has consistently interpreted the BACT requirement as containing two core criteria: First, the BACT analysis must include consideration of the most stringent available technologies, *i.e.*, those that provide the "maximum degree of emissions reduction." Second, any decision to require as BACT a control alternative that is less effective than the most stringent available must be justified by an analysis of objective indicators showing that energy, environmental, and economic impacts render the most stringent alternative unreasonable or otherwise not achievable. U.S. EPA has developed what it terms the "top-down" approach for conducting BACT analyses and has indicated that this approach will generally yield a BACT determination satisfying the two core criteria. Under the "top-down" approach, progressively less stringent control technologies are analyzed until a level of control considered BACT is reached, based on the environmental, energy, and economic impacts. The top-down approach was utilized in this BACT analysis.

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

1) Identification of available control technologies;
2) Technically infeasible alternatives are eliminated from consideration;
3) Remaining control technologies are ranked by control effectiveness;
4) Evaluation of control technologies for cost-effectiveness, energy impacts, and environmental effects in order of most effective control option to least effective; and
5) Selection of BACT.

In its *PSD and Title V Permitting Guidance for Greenhouse Gases* (November 2010), EPA reiterates that this is also the recommended process for permitting of GHG emissions under the PSD program. As such, this BACT analysis follows this 5-step approach.

6.1 Combustion Turbines

The proposed combustion turbines will produce CO_2 emissions from the combustion of methane and other minor hydrocarbon constituents in the natural gas. Small quantities of CH_4 and N_2O will also be emitted based on emission factors required for use in the Mandatory Greenhouse Gas Reporting Rules. A RACT/BACT/LAER Clearinghouse (RBLC) database search of CO_2 and CO_2e emissions from simple cycle natural gas fired combustion turbines utilized for providing peaking electrical capacity was conducted to identify potential controls and performance standards. Additionally, a search of recently submitted GHG permit applications to USEPA Region 6 was conducted to supplement the RBLC search. The search identified several projects of peaking electrical generating simple cycle combustion turbines.

NRG Texas defined the proposed project to meet market requirements in its service area. The objective of the project is to support existing generator resources during periods of increasing (peak) power demand. The proposed project at the Robinson site will utilize existing turbines that will be relocated from another site. The search of the database identified results describing only new simple cycle combustion turbines. It is important to note that USEPA's PSD and Title V permitting guidance for GHGs states:

> *"a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant."*

On March 27, 2012, USEPA proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources for Electric Utility Generating Units (EGU GHG NSPS). The proposed NSPS contains an output based CO_2 standard for combined cycle technology, which as of this application is not final. However, the proposed rule as published is not applicable to simple cycle combustion turbines per 40 CFR Part 60.5520(d). Therefore the BACT analysis presented below is based on RACT/BACT/LAER Clearinghouse (RBLC) database search and permit applications that have been submitted to EPA Region 6 for simple cycle combustion turbine peaking units.

6.1.1 Step 1 – Identification of Potential Control Technologies

- *Periodic Maintenance and Tune-up* – Periodic tune-up of the turbines helps to maintain optimal thermal efficiency. After several months of operation of the combustion turbines, fouling and degradation results in a loss of thermal efficiency. A periodic maintenance program consisting of inspection of key equipment components and tune up of the combustor will restore performance to near original conditions. The manufacturer of the proposed turbines has an extensive inspection and maintenance program that NRG Texas can implement.

- *Good Combustion Practices* – Good combustion practices include general accepted operating practices that allow for operating the proposed turbines in a manner to maximize efficiency at the lowest possible emissions of GHG. Efficient tuning of the air-to-fuel ratio in the combustion zone minimizes generation of unburned carbon.

- *Design/Selection of SCCT* – Simple cycle gas turbines that meet the requirements of supplying electricity during peak times and are efficient in providing the lowest possible cost to consumers are important considerations in selection of turbines. For the purpose of this application, NRG Texas will discuss using both combined cycle and simple cycle designs to satisfy customer requirements. Good turbine design and operation is important in maximizing efficiency of the turbines.

- *Instrumentation and Controls* – Proper instrumentation ensures efficient turbine operation to minimize fuel consumption and resulting GHG emissions. F-Class turbines like those being considered for this project include a digital control package. These systems control turbine operation, including fuel and air flow, to optimize combustion for control of criteria pollutant emissions (NO_x and CO) in addition to maintaining high operating efficiency to minimize fuel usage over the full range of operating conditions and loads.

- *Fuel Pre-Heating* – Thermal efficiency of the turbines can be increased by pre-heating the fuel prior to combustion. In combined cycle turbines, this is usually accomplished by heat exchange with hot water from the HRSG. In simple cycle turbines, either an electric heater or a small gas-fired heater is usually used.

- *CO_2 Capture and Storage* – Capture and compression, transport, and geologic storage of the CO_2 is a post-combustion technology that is not considered commercially viable at this time for natural gas combustion sources. However, based on requests by EPA Region 6 for other GHG permit applications, carbon capture and sequestration (CCS) is evaluated further in this analysis.

- *Use of Low Carbon Fuel (other than natural gas)* – Natural gas is the lowest carbon fossil fuel that is available at the site. Some fuel gas, which contains significant amounts of hydrogen, which produces no CO_2 when burned, can be burned in specially designed turbines if available and is an effective means of reducing GHG emissions in such situations.

6.1.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered "technically" feasible for the proposed turbines. NRG Texas successfully uses all of these efficiency and control measures, with the exception of CO_2 capture and storage and use of low carbon fuel gas (containing hydrogen), on similar simple cycle facilities at other existing electric generating stations; thus, they are considered viable for the proposed facilities.

NRG Texas is currently in the process of permitting a CCS demonstration project (supported by federal grant funds) to be applied to a slip stream from the exhaust from one of its coal fired generating units at another station in Texas. However, CCS is not considered to be a viable commercially proven alternative for controlling GHG emissions from natural gas fired peaking facilities at the current time. This conclusion is supported by the EPA's BACT guidance document PSD *and Title V Permitting Guidance for Greenhouse* Gases (March 2011) page 33 which states,

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

Another CCS project that EPA Region 6 has requested to be addressed in GHG BACT analyses is the Indiana Gasification Project. This project differs from the Robinson Project in several significant ways. The Indiana project will gasify coal, with the primary product being substitute natural gas (SNG), or methane. When coal is gasified, the product is a mixture consisting primarily of CO, CO_2, and H_2. A series of reactions is then used to convert the CO and H_2 to methane. To meet pipeline specifications, the CO_2 must be removed from the SNG, which produces a relatively pure CO_2 stream that is inherently ready for sequestration. Combustion turbines on the other hand produce an exhaust stream with a low CO_2 concentration. According to the Interagency Task Force on CCS, the exhaust from natural gas-fired combustion turbines contains only 3 to 4 percent CO_2. This low concentration of CO_2 from a natural gas-fired combustion turbine adds technical challenges for the adsorption or absorption of CO_2 compared to other commercial applications.

Other technical challenges occur with the application of CO_2 capture to a simple cycle peaking turbine application. The exhaust temperature can be up to 1,000 degrees F from the proposed turbines, which is much higher than any existing pilot application for a CO_2 capture system. For CO_2 capture to be effective, additional process steps of cooling the exhaust gases would have to be employed on the turbines. The peaking operation of the proposed gas turbines presents another challenge since these units start up quickly, within 10 minutes, and may not operate for long durations. The adsorption or absorption process in a CO_2 capture system is not likely to start up as quickly as a fast-start peaking turbine, limiting the amount of CO_2 that can be captured.

Thus, while the Indiana Gasification Project will produce a CO_2 byproduct that is amenable to sequestration or use in enhanced oil recovery without significant further processing, the Robinson peaking turbines will not. Separation (purification) of the CO_2 from the turbine combustion exhaust streams requires additional costly steps not otherwise necessary to the process.

To satisfy EPA Region 6 requests, NRG Texas has assumed that CCS is a viable control option in the remainder of this BACT analysis.

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel to CO_2. Fuels available to be used in industrial processes and power generation typically include coal, fuel oil, natural gas, or process fuel gas. Of these, natural gas is typically the lowest carbon fuel that can be burned, with a CO_2 emission factor in lb/MMBtu about 55% of that of subbituminous coal. Process fuel gas is a byproduct of chemical processes, which typically contains a higher fraction of longer chain carbon compounds than natural gas and thus results in more CO_2 emissions. Table C-2 in 40 CFR Part 98 Subpart C, which contains CO_2 emission factors for a variety of fuels, gives a CO_2 factor of 59 kg/MMBtu for fuel gas compared to 53.02 kg/MMBtu for natural gas. Of over 50 fuels identified in Table C-2, coke oven gas, with a CO_2 factor of 46.85 kg/MMBtu, is the only fuel with a lower CO_2 factor than natural gas, and is not an available fuel for the proposed project. Use of a completely carbon-free fuel such as 100% hydrogen, has the potential of reducing CO_2 emissions by up to 100%. Hydrogen fuel, in any concentration, is not a readily available fuel for most electric generating facilities and is only a viable low carbon fuel at industrial plants that generate hydrogen internally. Hydrogen is not produced at the Robinson Station and is not an available fuel for the proposed turbines. Natural gas is the lowest carbon fuel available for use in the proposed facilities; thus, use of low carbon fuels, other than natural gas, was eliminated due to lack of availability.

6.1.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

- CO_2 capture and storage,
- Turbine selection and design,
- Instrumentation and control system,
- Fuel pre-heating,
- Good combustion practices,
- Periodic maintenance and tune-ups.

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

Selection and design of the turbine system that meets the system requirements is important and is capable of maximizing the turbine efficiency and thus providing the lowest possible emissions.

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

- Gas flow rate monitoring,
- Fuel gas flow and usage,

- Exhaust gas temperature monitoring,
- Pressure monitoring around the turbine package,
- Temperature monitoring around the turbine package,
- Vibration monitoring, and
- Air/fuel ratio monitoring.

At similar NRG Texas facilities, periodic maintenance and tune-ups of existing turbines are performed per the manufacturer's recommended program. These programs consist of thorough inspection and maintenance of all turbine components on a daily, monthly, semi-annual, or annual frequency depending on the parameter or component and as recommended by the turbine vendor.

The effectiveness of instrumentation and control, maintenance and tune-ups, and fuel pre-heating cannot be quantitatively estimated, but are each generally in the <1% to 3% range, but any attempt to rank them in order of effectiveness would not be meaningful.

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

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

CCS - The technology to capture and store CO_2 in permanent underground storage facilities exists and has been used in limited pilot applications, but as stated previously, is not economically viable for most commercial applications. However, since the technology has been demonstrated on some processes and is potentially feasible for the proposed turbines, it cannot be completely ruled out based only on technical infeasibility; therefore, a cost effective analysis was performed for this option. The results of the analysis, presented in Tables 6-1 and 6-2, show that the cost of CCS for the project would be approximately $119 per ton of CO_2 controlled, which is not considered to be cost effective for GHG control. This equates to a total cost of about $30,000,000 per year for the six peaking turbines. The estimated total capital cost of the proposed project is $136,000,000. Based on a 7% interest rate, and 20 year equipment life, this cost equates to an annualized cost of about $13,000,000 for the project alone. Thus, the annualized cost of CCS would exceed the cost of the entire project without CCS. An additional cost of this magnitude would make the project economically unviable; therefore, CCS was rejected as a control option on the basis of excessive cost.

It should be noted that the cost per ton factors used for the CCS cost analysis were developed for a baseload plant that would typically have a capacity factor of about 80%. The capital cost of a CCS system for a super-peaking plant of the same capacity with a 10% capacity factor (the 3-year average capacity factor that the proposed facility will be limited to) would be the same; however, the CO_2 emissions reduction would be about one-eighth of that of the baseload plant. Thus, the capital cost component of the $/ton factor would be about eight times higher than that of the baseload plant. As such, the actual cost effectiveness of CCS for the proposed facility would be much higher than $119/ton. Additional technical and logistical challenges exist with the required intermittent operation of a CCS system that would likely render the system technically infeasible for a super-peaking power facility.

There are additional negative impacts associated with use of CCS. The additional process equipment required to separate, cool, and compress the CO_2 would require a significant additional power and energy expenditure. This equipment would include amine units, cryogenic units, dehydration units, and compression facilities. The power and energy must be provided from additional combustion units, and/or increase the parasitic load on the proposed facilities which significantly reduces the net heat rate (efficiency) of the plant. Significant additional GHG emissions, as well as additional criteria pollutant (NO_x, CO, VOC, PM, SO_2) emissions, would occur per MW of net electricity produced.

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

Turbine Selection and Design - In accordance with EPA guidance, a natural gas-fired combined cycle CT power plant is to be considered as a potential control option when proposing gas turbines. A combined cycle power plant is typically more energy efficient than a comparable simple cycle power plant due to the fact that a portion of the thermal energy contained in the turbine exhaust gas is recovered in a heat recovery unit. The heat is then used to generate steam to drive a steam turbine and produce additional power output. Typically, a combined cycle gas turbine is used to provide base or immediate power load due to the fact that combined cycle plants take longer to startup and shutdown; therefore, it operates most efficiently for extended periods of time, 50 to 98% loading, compared to the 10% annual capacity factor of the proposed facility. Whereas, for a peaking unit, a simple cycle turbine by its design can startup and shutdown in typically twenty minutes or less. This operating configuration of quick startup provides the peak power demand of the electric grid during maximum demand periods. Even though combined cycle plants provide greater efficiencies for base loading, simple cycle units are a better fit for the operating requirements of short term peak demand. Therefore, combined cycle gas turbine option was rejected for this proposed project.

The RBLC and USEPA Region 6 search also indicated one site in south Texas proposing to use simple cycle reciprocating engines as peaking units. NRG Texas rejected the use of reciprocating engines due to higher emissions of NO_x and other criteria pollutants, in some cases two to three times higher from reciprocating engines, compared to gas turbines.

NRG Texas is proposing to use existing simple cycle gas turbine units that are being relocated from another site. Table 6-3 indicates that when compared to other simple cycle turbines, the proposed GE 7B/E units have similar GHG emission rates per unit of power output. Table 6-3 shows a GHG emission rate range of 1,100 to 1,600 lb CO_2e/MWh for various simple cycle turbines in permits that have been recently issued or are currently under review by either the USEPA or state agencies. The CO_2e emissions from the proposed turbines for the

Robinson project will range from about 1,350 to 1,600 lb/MWh at full load, depending on ambient conditions. When corrected to ISO conditions, CO_2e emissions are projected to average no more than 1,450 lb/MWh over any 365 day period. Peak power requirements in Texas occur during hot summer months, conditions which are not conducive to the most efficient turbine operation. Although peaking needs may also be primarily in the summer in northern states, the lower ambient temperature results in more efficient turbine operation and lower GHG emissions per MWh. The fact that the proposed turbines are not new units will also contribute to a somewhat lower efficiency compared to the units in Table 6-3. Selection of used turbines for the proposed facility is a prudent decision. The turbines still have useful remaining life, and selecting them for the project avoids the environmental impacts, including increased GHG and other pollutant emissions associated with manufacture of new units in addition to providing a more economical source of power to consumers.

Instrumentation and Controls - Instrumentation and controls that can be applied to the combustion turbines are identified in Section 6.1.1 and are considered an effective means of control for the proposed turbine configuration.

Fuel Pre-Heating – Thermal efficiency of the combustion turbines increases with increased fuel temperature. A small natural gas-fired heater can be used for this purpose for turbines in simple cycle operation.

Good Combustion Practices – Maintaining proper air to fuel ratios helps ensure complete combustion of the natural gas in the turbine. NRG Texas will utilize these practices for the proposed project.

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

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

6.1.5 Step 5 – Selection of BACT

The following specific BACT practices are proposed for the turbines:

Proposed BACT Turbine Work Practices and Operational Requirements:

Turbine Design – The turbines are designed for maximum efficiency and to burn natural gas only.

Periodic Maintenance and Tune-up – Preventative maintenance, cleaning, and implementation of the manufacturer's recommended inspection and maintenance program will be followed to ensure continued operation at maximum thermal efficiency.

Fuel Pre-Heating – A small natural gas-fired heater will be used to pre-heat the natural gas prior to combusting it in the turbines.

Instrumentation and Controls – Instrumentation and controls will be applied to the combustion turbines for effective control of turbine operation. NRG Texas shall install an instrumentation and control package as provided by the turbine manufacturer. This includes:

- The gross energy output (MWh) will be measured and recorded hourly,
- The natural gas fuel flow rate shall be measured and recorded using non-resettable elapsed flow meters on each turbine,
- The air/fuel ratio shall be calculated and recorded daily, and
- Natural gas used in the turbines will be sampled and analyzed once per quarter for speciated gas composition. The sampled data will be used to calculate GHG emissions to show compliance with the emission limit.

Proposed Emission Limits

- NRG Texas proposes to limit emissions from the Robinson peaking turbines to 1,450 lbs of CO_2e per MWh (gross, corrected to ISO conditions), based on a rolling 365-day average, excluding startup and shutdown periods. Correction to ISO conditions will be performed in accordance with the procedure described in Appendix C using turbine-specific correction curves provided by GE.
- NRG Texas will limit total annual emissions of CO_2e to 94,543 tpy per turbine, based on a rolling 365-day average.
- NRG Texas will limit emissions of CO_2e during startup and shutdown of the turbines to an average of 8.2 tons per event per turbine, based on a 365-day rolling average basis.

6.2 Fuel Gas Heater

The fuel gas heater will be a minor source of GHG emissions. The total CO_2e emission rate will be about 2,700 tpy, which is 0.5% of the total project GHG emissions.

6.2.1 Step 1 – Identification of Potential Control Technologies

The potentially applicable GHG control technologies for the fuel gas preheater include:

- Use of low carbon fuel.
- Periodic Tune-up – Periodically tune-up of the heater to maintain optimal thermal efficiency.
- Heater Design – Good heater design to maximize thermal efficiency,
- Heater Air/Fuel Control – Monitoring of oxygen concentration in the flue gas to be used to control air to fuel ratio on a continuous basis for optimal efficiency.
- Waste Heat Recovery – Use of heat recovery from the heater exhaust elsewhere at the site.
- CO_2 Capture and Storage (CCS) – Capture and compression, transport, and geologic storage of the CO_2.

6.2.2 Step 2 – Elimination of Technically Infeasible Alternatives

Use of low carbon fuel, periodic tune-up, and good heater design are technically feasible control technologies for a small fuel gas heater such at the heater proposed for use at Robinson. In this instance, an existing heater that will be purchased as part of the turbine package will be used, making heater design not applicable. Monitoring of air/fuel ratio, use of waste heat recovery, and CCS are not considered to be technically feasible for equipment of this size that is in intermittent operation.

6.2.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Two feasible control technologies remain. Of these, use of low carbon fuel is considered to be more effective than periodic tune-ups.

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

Natural gas is a low carbon fuel and is the proposed fuel for use in the turbines and is thus readily available for use in the fuel gas heater. As discussed in Section 6.1.2, no other fuels with a lower carbon content are available at the site. Periodic tune-ups will have a neglible effect on the thermal efficiency of the heater for several reasons. First, the simple design of a heater of this type includes no significant components that require periodic maintenance to maintain good thermal efficiency. Second, due to the small size and intermittent operation, which result in an insignificant amount of GHG emissions, any marginal efficiency improvement would not result in a quantifiable reduction in total GHG emissions.

6.2.5 Step 5 – Selection of BACT

Use of low carbon natural gas as the only fuel is proposed as BACT to limit GHG emissions from the fuel gas heater to no more than 2,716 tpy of CO_2e. The GHG emissions will be further minimized by the limited use of the heater that is inherent and collateral with the limited operating schedule of the proposed super-peaking combustion turbines.

6.4 Process Fugitives

Small amounts of methane emissions may occur from leaking natural gas piping components (process fugitives) associated with the proposed project. The methane emissions from processes fugitives have been conservatively estimated to be 384 tpy as CO_2e. This is a negligible contribution to the total GHG emissions from the project; however, for completeness, they are addressed in this BACT analysis.

6.4.1 Step 1 – Identification of Potential Control Technologies

A search of the RACT/BACT/LAER Clearinghouse (RBLC) database and permit applications that have been submitted to EPA Region 6 for fugitive emissions from simple cycle combustion turbine peaking units was conducted to determine possible BACT technologies.

Based on these searches, the following available control technologies were identified.

- Install leakless technology components to eliminate fugitive emission sources; and
- Implementing an LDAR program.

6.4.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered "technically" feasible.

6.4.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Leakless components - By installing leak free valves and piping systems the site could achieve close to 100% reduction in GHG (methane) emissions from leaking valves in natural gas service.

LDAR program – A formal LDAR program could control GHG fugitive emissions by at least 75%.

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

Leakless components - Leakless technology components are available and currently in use in operations that produce or use highly toxic and hazardous materials. These operations represent a serious threat to human health from even the smallest amount of fugitive emissions; therefore, leakless technology is a practical cost effective technology to use in highly toxic or hazardous environments. These technologies have not been incorporated as BACT into the designs of natural gas fired electric generating stations, such as the proposed Robinson site, since there are no highly toxic or hazardous materials used or produced by the site. Recognizing that leakless technologies have not been universally adopted as LAER or BACT, even for toxic or extremely hazardous services, it is reasonable to state that these technologies are impractical for control of GHG emissions. Any further consideration of available leakless technologies for GHG controls is not appropriate; therefore, this control is rejected from further consideration.

LDAR program – Although technically feasible, use of an LDAR program to control the negligible amount of GHG emissions that may occur from process fugitives at the Robinson site is clearly not cost effective due to the already insignificant level of emissions. However, a cost effectiveness analysis for a basic LDAR program to control process fugitive CH_4 emissions is presented in Table 6-4 to demonstrate this point. The analysis shows that even the least stringent LDAR program (TCEQ's 28M program) would cost $48/ton of CO_2e

controlled. This cost is considered excessive for GHGs. The primary purpose of implementing an LDAR program as BACT is to control fugitive emissions of VOCs to the atmosphere. TCEQ guidance suggests that an LDAR program is not necessary to satisfy BACT when uncontrolled fugitive VOC emissions are less than 10 tpy. Because the fugitive VOC emissions from the proposed project would not meet the 10 tpy threshold, the TCEQ would not require NRG Texas to implement LDAR for VOC control. Since LDAR is not being implemented at the site for VOC control, and the cost of the program to control GHG emissions alone would be excessive, NRG Texas rejected LDAR from further consideration.

6.4.5 Step 5 – Selection of BACT

Due to the negligible amount of GHG emissions from process fugitives, implementation of an LDAR program or installing leakless components is clearly not cost effective and would result in no significant reduction in overall project GHG emissions. Based on these considerations, BACT for the Robinson site is determined to be using high engineering standards for the selection of equipment and following normal plant maintenance practices as needed for a safety and reliability purposes.

6.5 MSS Emissions from Gaseous Fuel Venting

Prior to maintenance of natural gas lines and unit startup, the lines must be vented to the atmosphere which results in CH_4 emissions due to the CH_4 content of the natural gas. While gaseous fuel venting prior to unit startup and for minor maintenance activities such as meter proving occurs frequently, the segment of pipeline isolated for these activities is small, resulting in minimal emissions of CH_4. On the other hand, occasional maintenance activities are required that involve venting of larger segments of pipeline. Emissions are minimized by limiting the frequency of occurrence to no more than one time per year for large segments of pipeline. This standard industry work practice is the only practical means of minimizing emissions and is therefore considered to be BACT for the proposed project.

6.6 SF_6 Emissions from Electrical Equipment Insulation

6.6.1 Step 1 – Identification of Potential Control Technologies

Emissions of sulfur hexafluoride (SF_6) due to leaks from the insulation used in new circuit breakers are estimated to be less than 3 lb/yr of actual mass emissions and less than 30 tpy of CO_2e. These emissions are negligible, and consideration of emissions controls for BACT purposes is not warranted. However, for completeness, they have been included in the BACT analysis. There are two methods for reducing or eliminating SF_6 emissions:

- Replace SF_6 with another insulation material, and
- Design the insulation systems to minimize SF_6 leaks.

6.6.2 Step 2 – Elimination of Technically Infeasible Alternatives

Both methods identified for reducing or eliminating SF_6 emissions are technically feasible for the project.

6.6.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Replacing SF_6 with another non SF_6 insulation material would provide 100% reduction in GHG from the process.
- Design of the insulation systems to minimize SF_6 leaks would be marginally effective in reducing the overall GHG emissions from the project.

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

Replace SF_6 with another insulation material - substitution of SF_6 with another non-GHG substance is determined to be technically infeasible. While dielectric oil or compressed air circuit breakers have been used historically, these units require large equipment components to achieve the same insulating capabilities of SF_6 circuit breakers. In addition, per the EPA:

> *"No clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties."*

SF_6 is a proven material for the proposed application and is considered to be a superior insulating material to alternatives currently available. Because even complete elimination of the emissions would result in no quantifiable benefit with respect to global warming potential, replacing it with an inferior alternative is not considered to be a prudent option and was eliminated from further consideration.

Design of the insulation systems to minimize SF_6 leaks - Modern high voltage circuit breakers are designed with totally enclosed insulation systems that result in minimal SF_6 leak potential. Alarm systems that can detect when a portion of the SF_6 has been lost from the system are available to identify leaks for repair before further losses occur. Although such systems would not necessarily be considered cost effective when expressed in traditional BACT $/ton of emissions avoided terms, their cost relative to the project cost is not prohibitive.

6.6.5 Step 5 – Selection of BACT

NRG Texas proposes to use circuit breakers with totally enclosed insulation systems equipped with a low pressure alarm and low pressure lockout. The lockout will prevent operation of the circuit breaker if insufficient SF_6 remains in the system.

Table 6-1 Cost Analysis for Post-Combustion CCS for Turbines

CCS System Component	Cost ($/ton of CO_2 Controlled)[1]	Tons of CO_2 Controlled per Year[2]	Total Annualized Cost
CO_2 Capture and Compression Facilities	$103	255,267	$26,292,486
CO_2 Transport Facilities (Table 6-2)	$15.67	255,267	$4,000,212
CO_2 Storage Facilities	$0.51	255,267	$130,186
Total CCS System Cost	$119	255,267	$30,422,884
Proposed Plant Cost	**Total Capital Cost**	**Capital Recovery Factor[3]**	**Annualized Capital Cost**
Cost of Proposed Units w/o CCS	$136,000,000	0.0944	$12,837,438

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

2. Tons of CO_2 controlled assumes 90% capture of all CO_2 emissions from the six turbines, based on 3-year average capacity factor of 10%.

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

Interest rate	7%
Equipent Life (yrs)	20

Table 6-2 CO_2 Pipeline Construction Cost Estimate

Description	Cost	Basis
Capital Cost:		
AGI Pipeline - 36" Diameter	$16,000,000	10-mile pipeline 24-inch diameter (10 miles is location of nearest pipeline or storage cavern). DOE/NETL calculation method (see below).
Total Capital Cost for CO2 Compression, Pipeline, and Well	**$16,000,000**	
Capital Recovery Factor[1]	0.0944	7% interest rate and 20 year equipment life
Annualized Capital Cost ($/yr)	**$1,510,287**	Total capital cost times capital recovery factor
Operating Cost:		
Power Cost, $/year	$489,925	10,000 hp electric compressor and $0.075/kwh electricity cost for 876 hours per year (based on 10% capacity factor)
O&M Cost, $/year	$2,000,000	O&M estimate
Total Annual Operating Cost ($/yr)	**$2,489,925**	
Total Cost:		
Total Annual Cost ($/yr)	**$4,000,212**	Annualized capital cost plus annual operating cost
GHG Emissions Controlled (ton/yr)	255,267	From GHG Calculations in Appendix A (based on 3-year average capacity factor of 10%)
Cost Effectiveness ($/ton)	**$15.67**	Total Annual Cost/GHG Emissions Controlled

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

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

Capital Cost for Construction of CO2 Pipeline to Nearest Storage Cavern:

Length in miles (L):	10
Diameter in inches (D):	24

Several candidate storage reservoirs exist within 10 to 50 miles of the proposed project; however, none of these have been confirmed to be viable for large scale CO2 storage at this time. However, it was assumed for this analysis that a suitable storage reservoir would be available within 10 miles.

Component	**Cost**	**Cost Equation[2]**
Materials	$4,390,095	Materials = $64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D + 26,960)
Labor	$8,064,863	Labor = $341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)
Miscellaneous	$3,456,190	Misc. = $150,166 + $1.58 x L x (8,417 x D + 7,234)
Right-of-Way	$571,669	Right-of-Way = $48,037 + $1.20 x L x (577 x D + 29,788)
Total Cost of Pipeline	**$16,482,816**	

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

Table 6-3 GHG Performance Limits for Simple Cycle Combustion Turbines

Project Information		Turbine Information		BACT Limits Proposed or Permitted	
Station	GHG Permit Status	Type	Capacity	lb CO_2e/MWh	Comments
Exelon LaPorte LP Mountain Creek SES Dallas County, TX	Application submitted to EPA Region 6	Siemens SGT6-5000F(4)	201.2 MW gross, ISO	NA	lb CO2e/MWh or equivalent limit not included in permit application
El Paso Electric Company Montana Power Station East El Paso County, TX	Application submitted to EPA Region 6	GE LMS100	100 MW	1,194	Proposed Limits
Cheyenne Prairie Generating Station Black Hills Corporation Cheyenne, WY	(PSD-WY-000001-2011.001)	GE LM6000 PF Sprint	37 MW	1,600	Limit as stated in permit
Puget Sound Energy Fredonia Generating Station Expansion Project Fredonia, WA	Permit Issued in 2013	GE 7FA.05	207 MW	1,299	Final limits, per net output
		GE 7FA.04	181 MW	1,310	
		SGT6-5000F4	197 MW	1,278	
		Two GE LMS100	100 MW, each	1,138	
Guadalupe Power Partners LP; Guadalupe Genrating Station	Application submitted to EPA Region 6	GE 7FA.03	191 MW	1,100	Proposed btu/kwh limits converted to lb CO2e/MWH using EPA factor of 53 kg/mmBtu
		GE7FA.04	165 MW (Note 1)	1,270	
		GE7FA-05	192 MW (Note 1)	1,250	
		SGT6-5000F(4)	227 MW	1,200	
Montana-Dakota Utilities Co. R.M. Heskett Station	Application submitted to North dakota Dept of Health	(GE) PG7121(7EA)	88 MW	NA	lb CO2e/MWh or equivalent limt not included in permit application
Golden Spread Electric Cooperative - Antelope Station	Application submitted February 2013	GE 7F-5-Series	202 MW	1,514	Proposed permit limit @ any load from 50% to 100% load
Golden Spread Electric Cooperative - Floydada Station	Application submitted February 2013	GE 7F-5-Series	202 MW	1,514	Proposed permit limit @ any load from 50% to 100% load
Sandy Hills Generating Station Spring Hill, Florida	Permit Issued January 2014	GE 7FA.05	218 MW	1,377	Final Limit, per gross MW, corrected to ISO conditions
NRG Texas Power LLC P.H. Robison Station Bacliff, Texas	Project proposed by this application	GE 7E	80 MW	1,450	Proposed limit, per gross MW, corrected to ISO conditions

Note 1: MW not expressed in permit application. Permit application stated MW for GE 7FA.03 and SGT6-5000(F) units only.

Calculation of lb/MWh at ISO Conditions (59°F and 60% RH), includes 2% heat rate degradation and 3% power output degradation:

Maximum firing rate:	783.8 MMBtu/hr
Gross Turbine Output:	63.1 MW
CO_2e Emissions Factor:	116.8 lb/MMBtu

CO_2e (lb/MWh) = 116.8 lb/MMBtu x 783.8 MMBtu/hr /63.1 MW

= 1,450 lb/MWh

Table 6-4 Cost Analysis for Natural Gas Fugitives LDAR Program

Monitoring Cost:	$2.50 per component per quarter
Number of Valves:	140 monitored
Number of Flanges:	350 not monitored
Number of PRVs:	10 monitored
Number of Pumps:	0 monitored
Number of Comps:	0 monitored
Total Number Monitored:	150 monitored
Total Cost of Monitoring:	$1,500 per year
Number of Repairs:	72 per year (12% of monitored components per quarter)
Cost of Repairs:	$12,240 per year @ $200 per component (85% of leaking components; remaining 15% only require minor repair)
Cost to re-monitor repairs:	$180 per year
Total Cost of LDAR:	$13,920 per year (montoring + repair + re-monitor)
Emission Reduction:	13.70 tpy of methane
Emission Reduction:	287.66 tpy of CO_2e
Cost Effectiveness:	$1,016 per ton of CH_4
Cost Effectiveness:	**$48** per ton of CO_2e

Appendix A

Emissions Calculations

Table A-1
NRG Texas P.H. Robinson Peaker Project
Turbine and Total GHG Emissions

Emission Factors

Constituent	CO2e Conversion Factor
CO2	1
CH4	25
N2O	298

Summary of GHG Emissions (CO2e)

FIN	EPN	Source	Fuel Rating (MMBtu/hr)*	Firing Rate (scf/yr)**	CO2 (tpy)	CH4 (tpy)	N2O (tpy)	CO2e (tpy)
PHR1	PHR1	Combustion Turbine 1	921.67	1,573,850,971	94,446	1.78	0.18	94,543
PHR2	PHR2	Combustion Turbine 2	921.67	1,573,850,971	94,446	1.78	0.18	94,543
PHR3	PHR3	Combustion Turbine 3	921.67	1,573,850,971	94,446	1.78	0.18	94,543
PHR4	PHR4	Combustion Turbine 4	921.67	1,573,850,971	94,446	1.78	0.18	94,543
PHR5	PHR5	Combustion Turbine 5	921.67	1,573,850,971	94,446	1.78	0.18	94,543
PHR6	PHR6	Combustion Turbine 6	921.67	1,573,850,971	94,446	1.78	0.18	94,543
FGHTR	FGHTR	Fuel Gas Heater	17.65	45,208,772	2,713	0.05	0.01	2,716
FUG-NGAS	FUG-NGAS	Fugitives	-	-	0.00	18	0	457
FUG-MSS	FUG-MSS	Gaseous Fuel Venting	-	-	0.00	8	0	188
INS-FS6	INS-FS6	SF6 from Circuit Breakers	-	-	-	-	-	26
TOTAL								570,645
Startup/Shutdown Events (average tons/event)								
			(MMBtu/event)	(scf/event)	CO2 (tons)	CH4 (tons)	N2O (tons)	CO2e (tons)
PHR-SU-SD	PHR-SU-SD	SU/SD - All Units	140.00	136,452	8.2	1.5E-04	1.5E-05	8.2

Notes:

* Firing rate is for peak emission conditions of 10°F and 75% relative humidity.

** Total annual firing rates and resulting emissions are intended to include startup/shutdown events.

Equation 98.33(a)(1): CO2, metric tons/yr = 1×10^{-3} x scf/yr x 1.026 MMBtu/scf $\times10^{-3}$ x 53.06 kgCO2/MMbtu

Metric tons were converted to short tons by multiplying by 1.102311 short tons per metric ton.

Default Nat. Gas Heating Value:	1.026E-03	mmbtu/scf (hhv)
Operating Hours	1,752	hr/yr
Startup Hours	150	hr/yr
Shutdown Hours	75	hr/yr
Fuel Gas Heater Operating Hrs:	2,628	hr/yr

CH4 and N2O Emission factors from Table C-2 of Appendix A to 40 CFR Part 98 Chapter C

	kg CH4 /mmBtu	kg N2O/mmBtu
Natural Gas	0.001	0.0001
Process Gas	0.003	0.0006

kg to lb conversion factor: 2.20462

Table A-2
NRG Texas P.H. Robinson Peaker Project
Fugitive Emissions

EPN:	FUG-NGAS	Fugitives: Natural Gas Piping		
Component Type	**Stream Type**	**Emission Factor SOCMI without Ethylene**	**Number of Components**	**Annual Emissions (tpy)**
Valves	Gas/Vapor	0.0089	140	5.4575
	Light Liquid	0.0035	0	0.0000
	Heavy Liquid	0.0007	0	0.0000
Pumps	Light Liquid	0.0386	0	0.0000
	Heavy Liquid	0.0161	0	0.0000
Flanges	Gas/Vapor	0.0029	350	4.4457
	Light Liquid	0.0005	0	0.0000
	Heavy Liquid	0.00007	0	0.0000
Compressors	Gas/Vapor	0.5027	0	0.0000
Relief Valves	Gas/Vapor	0.2293	10	10.0433
Open Ends		0.004	0	0.0000
Sample Con.		0.033	0	0.0000
Other	Gas/Vapor	0	0	0.0000
	Lt/Hvy Liquid	0	0	0.0000
Process Drains		0.07	0	0.0000
Total			**500**	**19.95**
% Methane				**91.57%**
Methane Emissions				**18.26**

Table A-3
NRG Texas P.H. Robinson Peaker Project
SF_6 Emission Calculations for Electrical Equipment Insulation Leaks

EPN: **INS-SF6**			
Emissions of from leaks of SF_6 gas used to insulate circuit breakers used in proposed plant.			
Estimated quantity of SF_6 in new equipment:		75	lb each times 6 units
	=	450	lb total
Annual Leak Rate:		0.50%	of quantity present
Annual Emission Rate:		2.25	lb/yr
	=	0.001125	tpy of SF6
Global Warming Potential Factor for SF_6:		22,800	
Annual Emission Rate (CO2 Equivalent):		**25.7**	**tpy of CO_2e**

Table A-4
NRG Texas P.H. Robinson Peaker Project
MSS - Gaseous Fuel Venting

Piping Description				Initial Conditions			Final Conditions				CH4	Event	CH4 Emissions
Location	Diameter (in) nom.	Diameter (in) act.	Length (ft)	Volume[1] (ft^3)	Press. (psig)	Temp. (°F)	Press. (psig)	Temp. (°F)	Volume[2] (scf)	Wt (lbs)	Wt (lbs)	Frequency (per yr)	Annual (tpy)
Unit 1 - startup	2.75	2.00	0.125	0.0027	300	68	5	68	0.05	0.002	0.002	1,095	0.001
Unit 2 - startup	2.75	2.00	0.125	0.0027	300	68	5	68	0.05	0.002	0.002	1,095	0.001
Lockout-tagout	2.75	2.00	20	0.44	300	68	0	68	10	0.44	0.401	1,000	0.200
Meter Proving	10	9.25	5	2	50	68	0	68	10	0.46	0.419	4	0.0008
											Total (ILE Activities)[4]		0.20

Piping Description				Initial Conditions			Final Conditions				CH4	Event	CH4 Emissions
Location	Diameter (in) nom.	Diameter (in) act.	Length (ft)	Volume[1] (ft^3)	Press. (psig)	Temp. (°F)	Press. (psig)	Temp. (°F)	Volume[2] (scf)	Wt (lbs)	Wt (lbs)	Frequency (per yr)	Annual (tpy)
Station Main Line	24	23.25	1,000	2,948	764	68	0	68	180,623	7,973	7,301	1	3.65
Main Line Pigging	24	23.25	1,000	2,948	764	68	0	68	180,623	7,973	7,301	1	3.65
											Total (Non-ILE Activity)[4]		7.30

1. Initial volume is calculated by multpilying the crossectional area by the length of pipe using the following formula: V_i = pi * [(diameter in inches/12)/2]^2 * length in feet = ft^3
2. Final volume calculated using ideal gas law $[(PV/ZT)_i = (PV/ZT)_f]$. $V_f = V_i (P_i/P_f)(T_f/T_i)(Z_f/Z_i)$, where Z is estimated using the following equation: $Z = 0.9994 - 0.0002P + 3E\text{-}08P^2$.
3. Additional Assumptions:

Nat Gas MW	17	lb/lbmol
Wt % Methane	91.57%	by Wt
Density of Nat. Gas	0.044	lb/scf

Appendix B

RBLC Search Results

Table B-1. RBLC and USEPA Region 6 Database Search Results for GHG Emissions from Gas Turbines

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS_NAME	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COMBUSTION TURBINE GENERATOR	154 MW	Carbon Dioxide Equivalent (CO2e)	None identified	774 LB/MW-HR
CA-1223	PIO PICO ENERGY CENTER	CA	11/19/2012	COMBUSTION TURBINES (NORMAL OPERATION)	300	Carbon Dioxide Equivalent	None identified	1328 lb/MW-H
ND-0028	R.M. HESKETT STATION	ND	02/22/2013 ACT	Combustion Turbine	986 MW	Carbon Dioxide Equivalent	None identified	413,198 TPY
ND-0029	PIONEER GENERATING STATION	ND	05/14/2013 ACT	Natural gas-fired turbines	451 MW	Carbon Dioxide Equivalent	None identified	243,146 TPY
ND-0030	LONESOME CREEK GENERATING STATION	ND	09/16/2013 ACT	Natural Gas Fired Simple Cycle Turbines	412 MW	Carbon Dioxide Equivalent	High efficiency turbines	220,122 TPY
LA-0257	SABINE PASS LNG TERMINAL	LA	12/06/2011	Simple Cycle Refrigeration Compressor Turbines (16)	286 MMBTU/H	Carbon Dioxide Equivalent (CO2e)	Good combustion/operating practices and fueled by natural gas - use GE LM2500+G4 turbines	4872107 TONS/YR
LA-0257	SABINE PASS LNG TERMINAL	LA	12/06/2011	Simple Cycle Generation Turbines (2)	286 MMBTU/H	Carbon Dioxide Equivalent (CO2e)	Good combustion/operating practices and fueled by natural gas - use GE LM2500+G4 turbines	4872107 TONS/YR
Region 6	El Paso Electric Company Montana Power Station	TX	3/25/2014	Simple Cycle Generation Turbines (4)	100 MW ea	Carbon Dioxide Equivalent (CO2e)	Evaporative cooling design; Installation of four LMS100 SCCTs; Use of natural gas as fuel; and Implementation of good combustion, operating, and maintenance practices	1100 lb CO2/MW-h (gross)
Region 6	ExTex LaPorte, LP Mountain Creek Steam Electric Station	TX	11/30/12	Simple Cycle Generation Turbines (2)	201.2 MW	Carbon Dioxide Equivalent (CO2e)	Fuel selection/switching; Efficient turbine/generator design; Good combustion practices; Burner management systems; Periodic tune-ups and maintenance.	1,169 lb CO2e/MWhr
Region 6	Guadalupe Power Partners LP Guadalupe Generating Station	TX	11/12/12	Simple Cycle Generation Turbines (2) GE 7FA.03 GE 7FA.04	157 165 192 203 MW	Carbon Dioxide Equivalent (CO2e)	Efficient CT design; inlet air cooling; burner maintenance and tuning.; Instrumentation and controls; use of clean fuels; Electric heating of the fuel gas	511,429 522,772 601,520 TPY
Region 6	South Texas Electric Cooperative Inc. Red Gate	TX	01/02/13	Simple Cycle Recipricating Engine peaking plant 12 RICE at 18.75 MW	225 MW	Carbon Dioxide Equivalent	energy-efficient SI RICE	1,193 lb CO2/MWh
TX-1358-GHG	Golden Spread Electric Coop Antelope Elk Energy Center	TX	Draft Permit May 2014	Natural Gas Fired Simple Cycle Turbine	202 MW	Carbon Dioxide Equivalent (CO2e)	Limited operation. Efficient Turbine Design	1304 lb/MW-hr gross
TX-13748-GHG	Indeck Wharton Energy Center	TX	Draft Permit May 2014	3 Natural Gas Fired Simple Cycle Turbine	2-15-225 MW	Carbon Dioxide Equivalent (CO2e)	Limited operation. Efficient Turbine Design	1276 lb/MW-hr gross
TX-13748-GHG	Indeck Wharton Energy Center	TX	Draft Permit May 2014	Two 165 MW Simple Cycle GE 7FA.03 Turbines'	165 MW	Carbon Dioxide Equivalent (CO2e)	Limited operation. Efficient Turbine Design	1393 lb/MW-hr gross

Search Date 5/7/20014

Table B-2. RBLC and USEPA Region 6 Database Search Results for GHG Emissions from Circuit Breakers

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS NAME	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT
Region 6	South Texas Elecric Cooperative Inc. Red Gate Power Plant	TX	01/02/13	ENCLOSED PRESSURE SF6 CIRCUIT BREAKERS	Sulfur Hexafluoride	None identified	23.9 TPY CO2e
CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	ENCLOSED PRESSURE SF6 CIRCUIT	Sulfur Hexafluoride	None identified	9.56 TPY CO2e
Region 6	El Paso Electric Company Montana Power Station	TX	3/25/2014	ENCLOSED PRESSURE SF6 CIRCUIT BREAKERS	Sulfur Hexafluoride	Use of state-of-the-art circuit breakers that are gas-tight; Implementing an LDAR program to identify and repair leaks	342 TPY CO2e
Region 6	ExTex LaPorte, LP Mountain Creek Steam Electric Station	TX	11/30/12	ENCLOSED PRESSURE SF6 CIRCUIT BREAKERS	Sulfur Hexafluoride	Implement modern state state-of- the-art, gas-tight circuit breakers; an inspection and maintenance program	16.73 TPY CO2e
Region 6	Guadalupe Power Partners LP Guadalupe Generating Station	TX	11/12/12	ENCLOSED PRESSURE SF6 CIRCUIT BREAKERS	Sulfur Hexafluoride	state-of-the-art enclosed pressure SF6 circuit breakers	82.5 TPY CO2e
CA-1223	Pico Energy Center	CA	11/19/2012	CIRCUIT BREAKERS	Sulfur Hexafluoride	Install, operate, and maintain enclosed pressure SF6 circuit breakers with maximum leak rate of 0.5% by weight	40.2 TPY CO2e
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/3/2012	ELECTRICAL CIRCUIT BREAKERS	Sulfur Hexafluoride	ALTERNATIVE TECHNOLOGY FULLY ENCLOSED CIRCUIT BREAKERS WITH LEAK DETECTION	0.0009
IN-0166	INDIANA GASIFICATION, LLC	IN	6/27/2012	ELECTRIC CIRCUIT BREAKER	Sulfur Hexafluoride	USE OF FULLY ENCLOSED PRESSURIZED SF6 CIRCUIT BREAKERS WITH LEAK DETECTION (LOW PRESSURE ALARM)	
TX-0612	THOMAS C. FERGUSON POWER PLANT	TX	11/10/2011	SF6 Insulated Electric Equipment	Sulfur Hexafluoride		131 tpy
TX-0632	DEER PARK ENERGY CENTER LLC	TX	11/29/2012	SF6-FUG	Sulfur Hexafluoride		0.0002 tpy
TX-0633	CHANNEL ENERGY ENERGY CENTER, LLC	TX	11/29/2012	SF6-FUG	Sulfur Hexafluoride		0.0002 tpy
TX-108130-	Chamisa Compressed Air Energy Storage Facility	TX	3/21/2014	SF6 Insulated Electric Equipment	Sulfur Hexafluoride	Instrument Monitoring and Alarm	None
TX-1364-GHG	FGE Texas Project, Mitchell County	TX	4/28/2014	SF6 Insulated Electric Equipment	Sulfur Hexafluoride	Instrument Monitoring and Alarm	None
TX-1358-GHG	Golden Spread Electric Coop Antelope Elk Energy Center	TX	Draft Permit May 2014	SF6 Insulated Electric Equipment	Sulfur Hexafluoride	Instrument Monitoring and Alarm	None
TX-1374-GHG	Indeck Wharton Energy Center	TX	Draft Permit May	SF6 Insulated Electric Equipment	Sulfur Hexafluoride	Instrument Monitoring and Alarm	None
TX-1366-GHG	Ector County Energy Center	TX	Draft Permit May	SF6 Insulated Electric Equipment	Sulfur Hexafluoride	Instrument Monitoring and Alarm	None
TX-1288-GHG	La Paloma Energy Center	TX	11/6/2013	SF6 Insulated Electric Equipment	Sulfur Hexafluoride	Instrument Monitoring and Alarm	23.9 tpy CO2e

Search Date 5/7/20014

Appendix C

ISO Correction Procedure

Procedure for determining CO_2 emissions corrected to ISO

Purpose
This document outlines the procedure to determine CO_2 emissions corrected to ISO operating conditions.

ISO Conditions for Gas Turbines are defined as:

59°F Dry Bulb
60% Relative Humidity or 0.0064 Specific Humidity
14.696 psia Barometric Pressure
0 inch H_2O Inlet dP
0 inch H_2O Exhaust dP

Summary
CO_2 can be directly measured, but it is simpler and sufficiently accurate to calculate it from the measured fuel composition and flow rate assuming 100% conversion of Carbon to Carbon Dioxide. Once the CO_2 quantity for a given test condition is known, vendor's gas turbine correction curves can be used to correct the gas turbine output and fuel consumption from test conditions to ISO conditions. From this, the CO_2 emissions corrected to ISO ($CO_{2,ISO}$) can be determined.

Procedure
Obtain vendor's correction curves for Output (P), Fuel Input (Q) and/or Heat Rate (HR). These curves are functions of Compressor Inlet Temperature (CIT), Specific Humidity (w), Barometric Pressure (baro), Inlet Pressure Loss (dP_I), and Exhaust Pressure Loss (dP_E). Sample curves (for a GE 7121EA) are included in Appendix A.

Using the correction curves for Output (P), lookup the correction values for each of the independent conditions (CIT, baro, w, dP_I, and dP_E) at both Test conditions and ISO conditions. Each independent condition will have a correction factor for both Test conditions and ISO conditions ($Corr,P_{Test}$ and $Corr,P_{ISO}$). These are combined to make the combined correction factor (Corr,P) as shown in Eq.1

Eq.1) $Corr,P = Corr,P_{ISO} / Corr,P_{Test}$

The Output, corrected to ISO (P_{ISO}), is determined by multiplying the measured Output (P_{Test}) by the product of Corr,P for each independent condition as shown in Eq.2

Eq.2) $P_{ISO} (MW_e) = P_{Test} \times Corr,P\ (CIT) \times Corr,P\ (w) \times Corr,P\ (baro) \times Corr,P\ (dP_I) \times Corr,P\ (dP_E)$

Repeat the above procedure for Fuel Input (Q) and/or Heat Rate (HR) to determine Q_{ISO} (MMBtu/hr HHV) and/or HR_{ISO} (Btu/kwh HHV).

If HR_{ISO} was obtained instead of Q_{ISO}, Q_{ISO} can be determined using Eq.3:

Eq.3) $Q_{ISO} = P_{ISO} \times HR_{ISO}$

Since CO_2 flow rate is directly proportional to fuel flow rate for a given fuel composition, the CO_2 flow rate at ISO ($CO_{2,ISO\ (klb/hr)}$) can be determined from the measured CO_2 flow rate ($CO_{2,Test\ (klb/hr)}$), Q_{ISO}, and Q_{Test} using Eq.4)

Eq.4) $CO_{2,ISO\ (klb/hr)} = CO_{2,Test\ (klb/hr)} \times (Q_{ISO} / Q_{Test})$

The lb/MWh CO_2 rate and lb/MMBtu HHV CO_2 rate at ISO can be determined from Eq.5 and Eq.6

Eq.5) $CO_{2,ISO(lb/MWh)} = CO_{2,ISO\ (klb/hr)} / P_{ISO}$

Eq.6) $CO_{2,ISO\ (lb/MMBtu\ HHV)} = CO_{2,ISO\ (klb/hr)} / Q_{ISO}$

Note that $CO_{2,ISO\ (lb/MMBtu\ HHV)}$ will always be equal to $CO_{2,Test\ (lb/MMBtu\ HHV)}$.

Appendix A: Sample Correction Curves

General Electric Model PG7121EA Gas Turbine

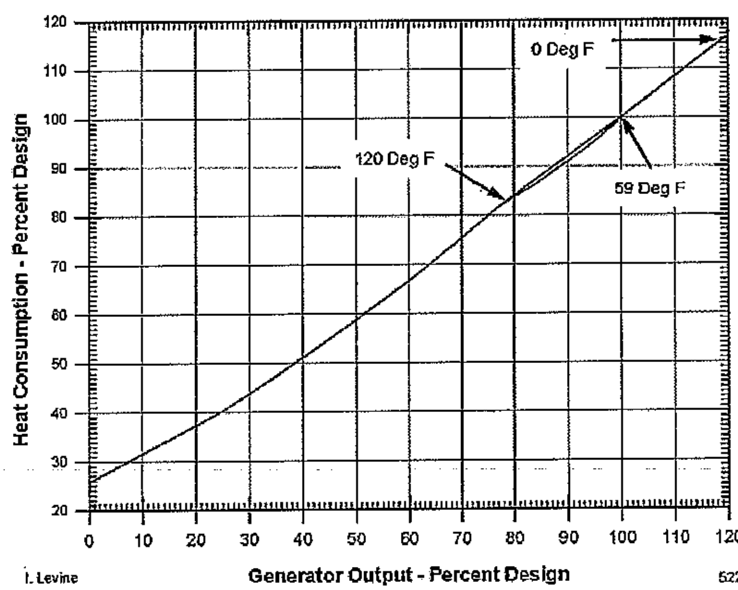
Estimated Performance - Configuration: DLN Combustor

Compressor Inlet Conditions 59 F (15 C), 60% Relative Humidity
Atmospheric Pressure 14.7 psia (1.013 bar)

Fuel:			Natural Gas		Distillate	
Design Output	kW		84360		87890	
Design Heat Rate (LHV)	Btu/kWh	(kJ/kWh)	10100	(11050)	10570	(11150)
Design Heat Cons (LHV)	Btu/h	(kJ/h)x10^6	934.1	(932.5)	876.1	(924.2)
Design Exhaust Flow	lb/h	(kg/h)x10^3	2361	(1071)	2369	(1074)
Exhaust Temperature	deg F	(deg C)	998	(536.7)	999	(537.2)
Load			Base		Base	

Notes
1. Altitude correction on curve 416HA662 Rev A
2. Ambient temperature correction on curve 522HA283 Rev 2
3. Effect of modulating IGV's on exhaust temperature and flow on curve 522HA284 Rev 2.
4. Humidity effects on curve 498HA697 Rev. B - all performance calculated with a constant specific humidity of .0064 or less as not to exceed 100% relative humidity
5. Plant Performance is measured at the generator terminals and includes allowances for the effects of inlet bleed heating, excitation power, shaft driven auxiliaries, and 3.5 in H2O (7.29 mbar) inlet and 5.5 in H2O (13.70 mbar) exhaust pressure drops and a DLN Combustor.
6. Additional inlet and exhaust pressure loss effects:

	% Effect on Output	% Effect on Heat Rate	Effect on Exhaust Temp
4 in Water (10.0 mbar) inlet	-1.40	0.42	1.9F (1.0C)
4 in Water (10.0 mbar) exhaust	-0.42	0.40	1.9F (1.0C)



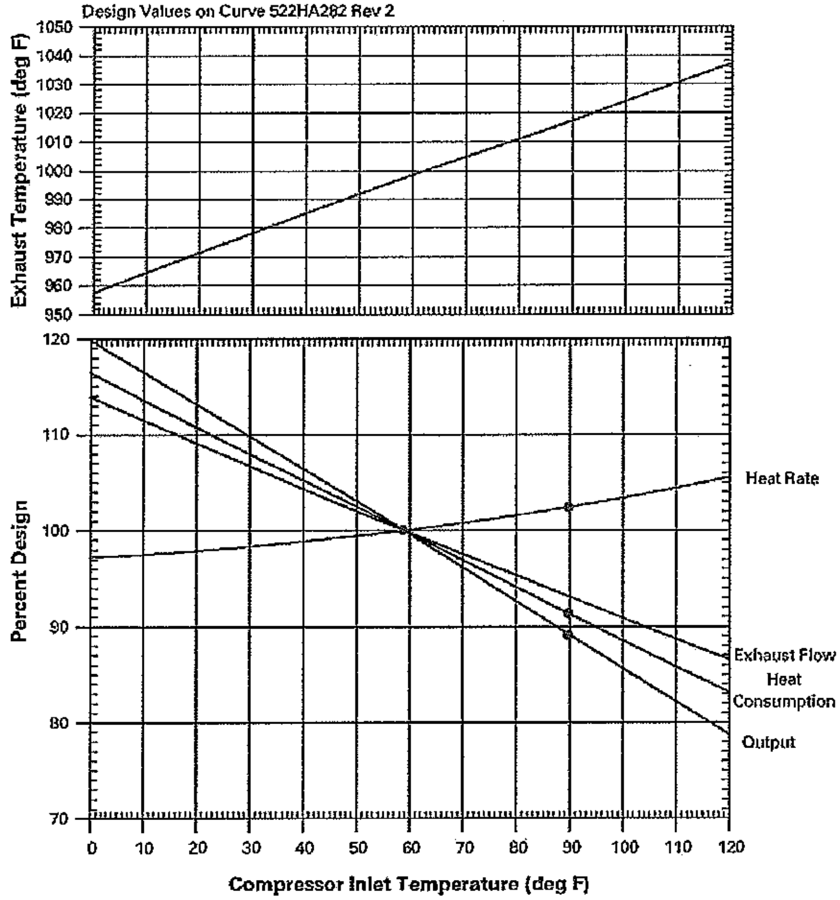
I. Levine
8/17/98

522HA282
Rev - 2

GENERAL ELECTRIC MODEL PG7121EA GAS TURBINE

Effect of Compressor Inlet Temperature on
Output, Heat Rate, Heat Consumption, Exhaust Flow
And Exhaust Temperature at Base Load and 100% speed.

Configuration: DLN Combustor
Fuel: Natural Gas
Design Values on Curve 522HA282 Rev 2



I Levine
8/17/98

522HA283
Rev - 2

GENERAL ELECTRIC GAS TURBINE ALTITUDE CORRECTION CURVE

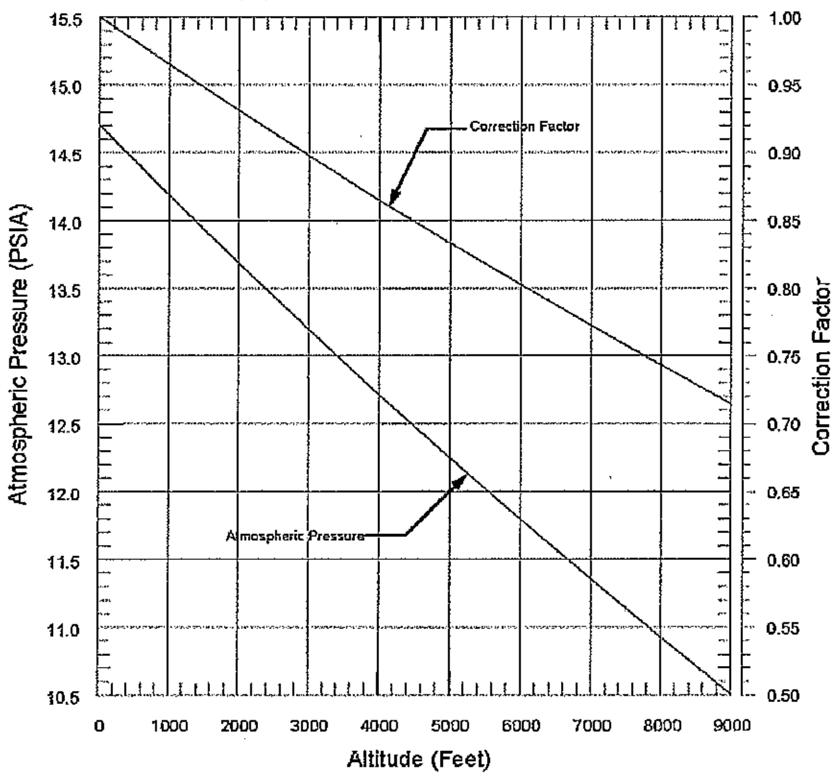
ALTITUDE VS ATMOSPHERIC PRESSURE

AND

ALTITUDE VS CORRECTION FACTOR

FOR GASTURBINE OUTPUT, FUEL CONSUMPTION, AND EXHAUST FLOW

NOTES.
1. Exhaust Temperature, Heat Rate, and Thermal Efficiency are not affected by altitude.
2. Correction Factor = P(atm)/14.7



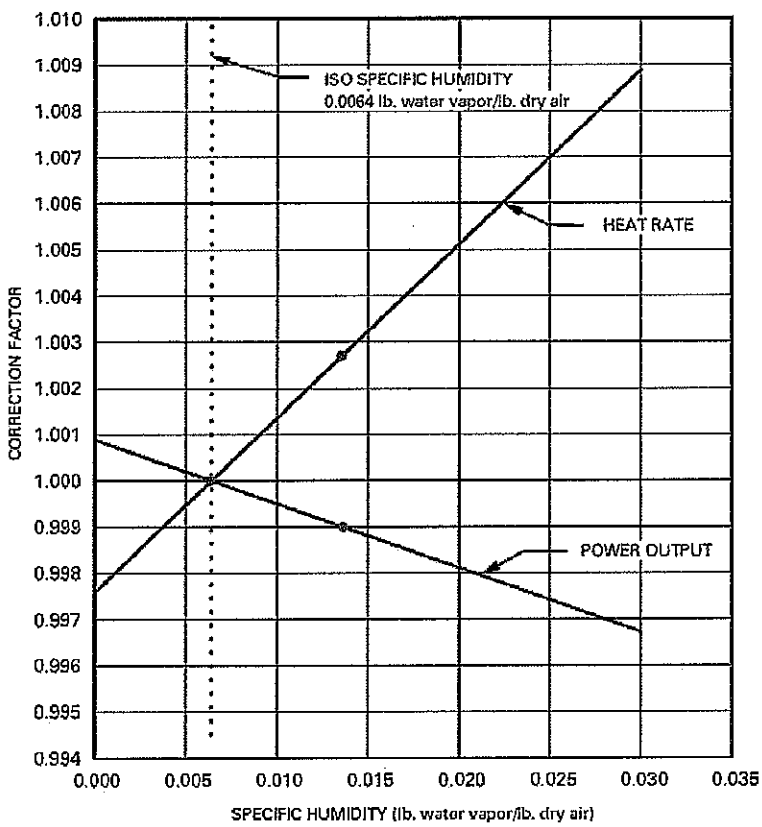
Gajipara H. N.
6/30/99

416HA662
Rev-B

General Electric MS6001, MS7001 And MS9001 Gas Turbines

Corrections To Output And Heat Rate
For Non-Iso Specific Humidity Conditions

For Operation At Base Load On Exhaust
Temperature Control Curve



10/10/89
DA JAQUEWAY

498HA697
REV B

Appendix B: Sample Calculations

This Appendix demonstrates the use of the procedures and equations presented previously to calculate CO_2 emissions for a typical gas fired simply cycle gas turbine and correct them to ISO conditions.

Reference and Test Conditions

Parameter	ISO Condition	Test Condition	Units
Compressor Inlet Temperature	59	90	°F
Relative Humidity	60	45	%
Specific Humidity	.0064	.01355	lb/lb
Barometric Pressure	14.696	14.750	psia
Inlet Pressure Loss	0	4.0	inch H_2O
Exhaust Pressure Loss	0	4.0	inch H_2O

Measurements at Test Conditions

Parameter	Value	Units
Output $_{gross}$	75.480	MW
Fuel Flow	38.05	klb/hr
Fuel Methane	90	% vol
Fuel Ethane	10	% vol

Results at Test Conditions

P_{Test} = 75.480 MW

Fuel Properties:
90% CH_4 vol%, 10% C_2H_6 vol%
82.76% CH_4 wt%, 17.24% C_2H_6 wt%
21,328 Btu/lb LHV
23,606 Btu/lb HHV

Fuel input:
Q_{Test} = (38.05 klb/hr) x (23,606 Btu/lb HHV) / 1000 = 898.21 MMBtu/hr HHV

$HR_{Test} = Q_{Test} / P_{Test}$ = (898.21 MMBtu/hr HHV) / (75.480 MW) x 1000 = 11,900 Btu/kwh HHV

$CO_{2,Test(klb/hr)}$ = (38.05 klb/hr) x [(0.8276 x 1 x (44.01/16.04) + (0.1724 x 2 x (44.01/30.07)] = 105.60 klb/hr

$CO_{2,Test(lb/MWh)} = CO_{2,Test\,(klb/hr)} / P_{Test}$
$CO_{2,Test(lb/MWh)}$ = (105.60 klb/hr) / (75.480 MW) x 1000 = 1399.0 lb/MWh

$CO_{2,Test\,(lb/MMBtu\,HHV)} = CO_{2,Test\,(klb/hr)} / Q_{Test}$
$CO_{2,Test\,(lb/MMBtu\,HHV)}$ = (105.60 klb/hr) / (898.21 MMBtu/hr HHV) x 1000 = 117.57 lb/MMMBtu HHV

Correction Factors

From GE curve 522HA283: CIT_{ISO} = 59°F, CIT_{Test} = 90°F

$Corr,P_{ISO}$ (CIT) = 100
$Corr,P_{Test}$ (CIT) = 89.11
Corr,P (CIT) = 100 / 89.11 = 1.1222

$Corr,Q_{ISO}$ (CIT) = 100
$Corr,Q_{Test}$ (CIT) = 91.34
Corr,Q = 100 / 91.34 = 1.0948

$Corr,HR_{ISO}$ (CIT) = 100
$Corr,HR_{Test}$ (CIT) = 102.50
Corr,HR = (CIT) 100 / 102.50 = 0.9756

From GE curve 498HA697: w_{ISO} = .006400 lb/lb, w_{Test} = .013553 lb/lb

$Corr,P_{ISO}$ (w) = 1.000
$Corr,P_{Test}$ (w) = 0.99900
Corr,P (w) = 1.000 / 0.99900 = 1.0010

$Corr,HR_{ISO}$ (w) = 1.000
$Corr,HR_{Test}$ (w) = 1.00272
Corr,HR = (w) 1.000 / 1.00272 = 0.9973

From GE curve 416HA662 (Notes: 1 & 2): $baro_{ISO}$ = 14.696 psia, $baro_{Test}$ = 14.750 psia

$Corr,P_{ISO}$ (baro) = 14.696 / 14.7 = 0.9997
$Corr,P_{Test}$ (baro) = 14.750 / 14.7 = 1.0034
Corr,P (baro) = 0.9997 / 1.0034 = 0.9963

From GE curve 522HA282 (Note: 6): $dP_{I,ISO}$ = 0 inch H_2O, $dP_{I,Test}$ = 4.0 inch H_2O

$Corr,P_{ISO}$ (dP_I) = 100 + ((0/4) x -1.40) = 100
$Corr,P_{Test}$ (dP_I) = 100 + ((4.00/4) x -1.40) = 98.60
Corr,P (dP_I) = 100 / 98.6 = 1.0142

$Corr,HR_{ISO}$ (dP_I) = 100 + ((0/4) x +0.42) = 100
$Corr,HR_{Test}$ (dP_I) = 100 + ((4.00/4) x +0.42) = 100.42
Corr,HR (dP_I) = 100 / 100.42 = 0.9958

From GE curve 522HA282 (Note: 6): $dP_{E,ISO}$ = 0 inch H_20, $dP_{E,Test}$ = 4.0 inch H_20

$Corr,P_{ISO}\ (dP_E) = 100 + ((0/4) \times -0.42) = 100$
$Corr,P_{Test}\ (dP_E) = 100 + ((4.00/4) \times -0.42) = 99.58$
$Corr,P\ (dP_E) = 100 / 99.58 = 1.0042$

$Corr,HR_{ISO}\ (dP_E) = 100 + ((0/4) \times +0.40) = 100$
$Corr,HR_{Test}\ (dP_E) = 100 + ((4.00/4) \times +0.40) = 100.40$
$Corr,HR\ (dP_E) = 100 / 100.40 = 0.9960$

Results Corrected to ISO

$P_{ISO} = P_{Test} \times Corr,P\ (CIT) \times Corr,P\ (w) \times Corr,P\ (baro) \times Corr,P\ (dP_I) \times Corr,P\ (dP_E)$
P_{ISO} = (75.480 MW) x 1.1222 x 1.0010 x 0.9963 x 1.0142 x 1.0042= 86.034 MW

$HR_{ISO} = HR_{Test} \times Corr,HR\ (CIT) \times Corr,HR\ (w) \times Corr,HR\ (baro) \times Corr,HR\ (dP_I) \times Corr,HR\ (dP_E)$
HR_{ISO} = (11,900 Btu/kwh HHV) x 0.9756 x 0.9973 x 1 x 0.9958 x 0.9960 = 11,484 Btu/kwh HHV

$Q_{ISO} = P_{ISO} \times HR_{ISO}$
Q_{ISO} = (86.034 MW) x (11,484 Btu/kwh HHV) / 1000 = 988.01 MMBtu/hr HHV

$CO_{2,ISO\ (klb/hr)} = CO_{2,Test\ (klb/hr)} \times (Q_{ISO} / Q_{Test})$
$CO_{2,ISO\ (klb/hr)}$ = (105.60 klb/hr) x (988.01 / 898.21) = 116.16 klb/hr

$CO_{2,ISO(lb/MWh)} = CO_{2,ISO\ (klb/hr)} / P_{ISO}$
$CO_{2,ISO(lb/MWh)}$ = (116.16 klb/hr) / (86.034 MW) x 1000 = 1350.2 lb/MWh

$CO_{2,ISO\ (lb/MMBtu\ HHV)} = CO_{2,ISO\ (klb/hr)} / Q_{ISO}$
$CO_{2,ISO\ (lb/MMBtu\ HHV)}$ = (116.16 klb/hr) / (988.01 MMBtu/hr HHV) x 1000 = 117.57 lb/MMMBtu HHV