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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

February 2013

United States | Canada | Brazil | UK | Ireland | Netherlands
Australia Asia Pacific | Russia | Middle East | Africa

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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 ^{o}F. The turbines will be fired exclusively with natural gas. The maximum operating rate of each unit will not exceed a 20% annual capacity (equivalent to 1,752 full load hours) in any single year or a 10% annual capacity factor (equivalent to 876 full load hours) averaged over any three year period. 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). Permitting of GHG emissions in Texas is currently conducted by the USEPA Region VI; therefore, a separate PSD permit application is required to be submitted to the USEPA for GHG emissions. 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

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, and permitting of other pollutants is being conducted by TCEQ, 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: 1201 Fannin, Suite 8802		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 713-537-2146	Fax No.: 713-795-7431	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: 1201 Fannin, Suite 8802		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 713-537-2146	Fax No.: 713-795-7431	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: 11/1/2013	Projected Start of Operation Date: 6/1/2014	
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 [signature] *Original Signature Required*		
DATE: 28 Feb 13		

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.:	**TBD**	Application Submittal Date:	**February 2013**
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	550,235
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-Nov-13				
Five years prior to start of construction								1-Nov-08				contemporaneous
Estimated start of operation								1-Jun-14				period
Net contemporaneous change, including proposed project, from Table 3F. (tpy)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	550,235
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.

[illegible] | Senior Manager | 28 Feb 13
Signature | Title | Date

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]			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)
	FIN	EPN	Facility Name								
1	PHR1	PHR1	Coimbustion Turbine 1	TBD		0	91,611		91,611	0	91,611
2	PHR2	PHR2	Combustion Turbine 2	TBD		0	91,611		91,611	0	91,611
3	PHR3	PHR3	Combustion Turbine 3	TBD		0	91,611		91,611	0	91,611
4	PHR4	PHR4	Combustion Turbine 4	TBD		0	91,611		91,611	0	91,611
5	PHR5	PHR5	Combustion Turbine 5	TBD		0	91,611		91,611	0	91,611
6	PHR6	PHR6	Combustion Turbine 6	TBD		0	91,611		91,611	0	91,611
7	FUG-NGAS	FUG-NGAS	Fugitives	TBD		0	384		384	0	384
8	FUG-MSS	FUG-MSS	Geseous Fuel venting	TBD			158		158		158
9	INS-FS6	INS-FS6	SF6 from Circuit Breakers	TBD		0	27		27	0	27
10						0			0	0	0
11						0			0	0	0
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
										Page Subtotal[9]:	**550,235**
										Project Total:	**550,235**

Table 3F
Project Contemporaneous Changes

Company: **NRG Texas Power LLC**

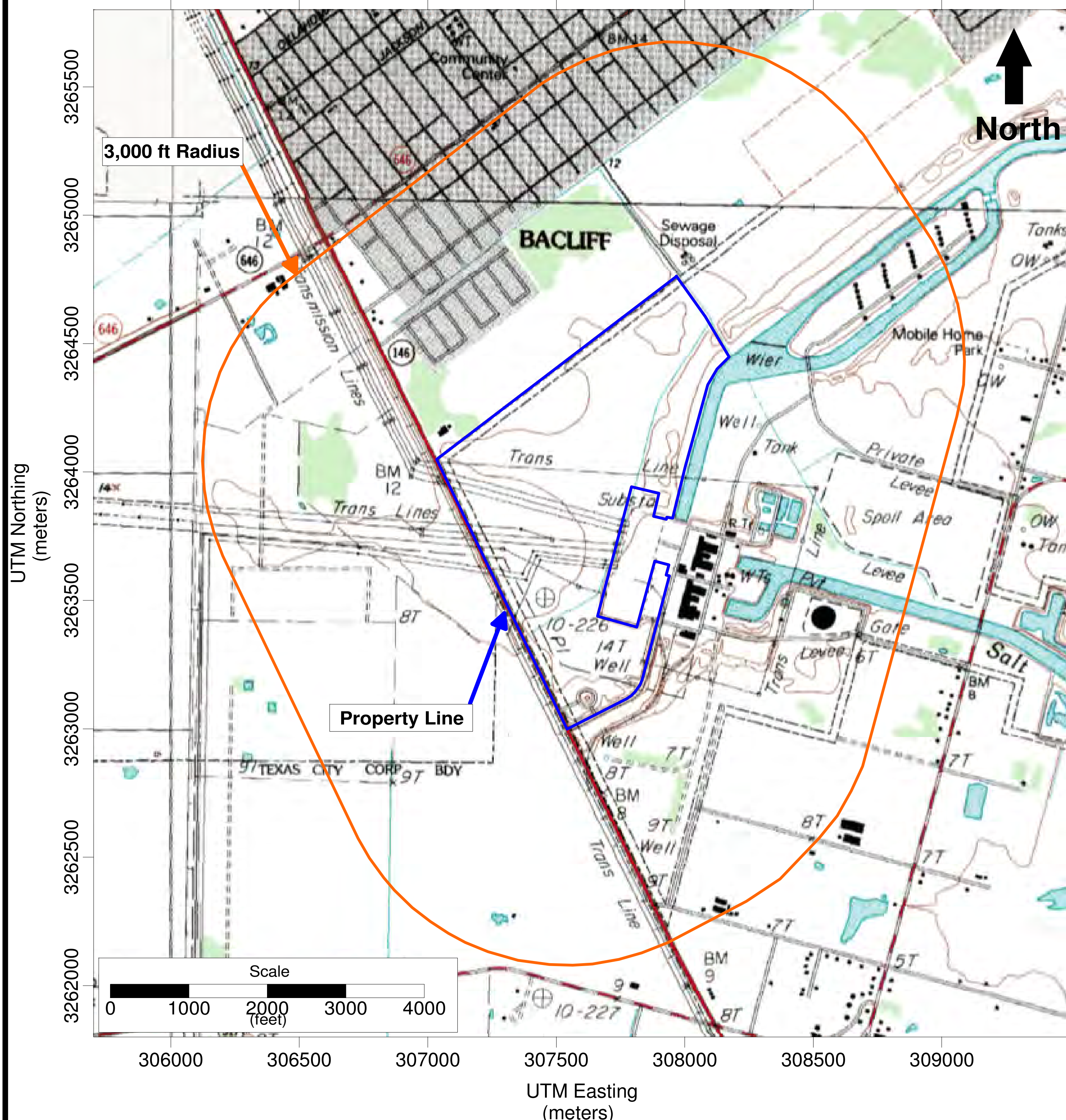
Criteria Pollutant: CO_2e

Permit Application No. **TBD**

No.	PROJECT DATE	EMISSION UNIT AT WHICH REDUCTION OCCURED FIN	EMISSION UNIT AT WHICH REDUCTION OCCURED EPN	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)
1	6/1/2014	PHR1	PHR1	TBD	Simple Cycle Peaking Plant	91,611	-	91,611	91,611
2	6/1/2014	PHR2	PHR2	TBD	Simple Cycle Peaking Plant	91,611	-	91,611	91,611
3	6/1/2014	PHR3	PHR3	TBD	Simple Cycle Peaking Plant	91,611	-	91,611	91,611
4	6/1/2014	PHR4	PHR4	TBD	Simple Cycle Peaking Plant	91,611	-	91,611	91,611
5	6/1/2014	PHR5	PHR5	TBD	Simple Cycle Peaking Plant	91,611	-	91,611	91,611
6	6/1/2014	PHR6	PHR6	TBD	Simple Cycle Peaking Plant	91,611	-	91,611	91,611
7	6/1/2014	FUG-NGAS	FUG-NGAS	TBD	Simple Cycle Peaking Plant	384		384	384
8	6/1/2014	FUG-MSS	FUG-MSS	TBD	Simple Cycle Peaking Plant	158		158	158
9	6/1/2014	INS-FS6	INS-FS6	TBD	Simple Cycle Peaking Plant	27		27	27
10								0	0
								PAGE SUBTOTAL:	550,235
	Summary of Contemporaneous Changes							TOTAL :	**550,235**

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.



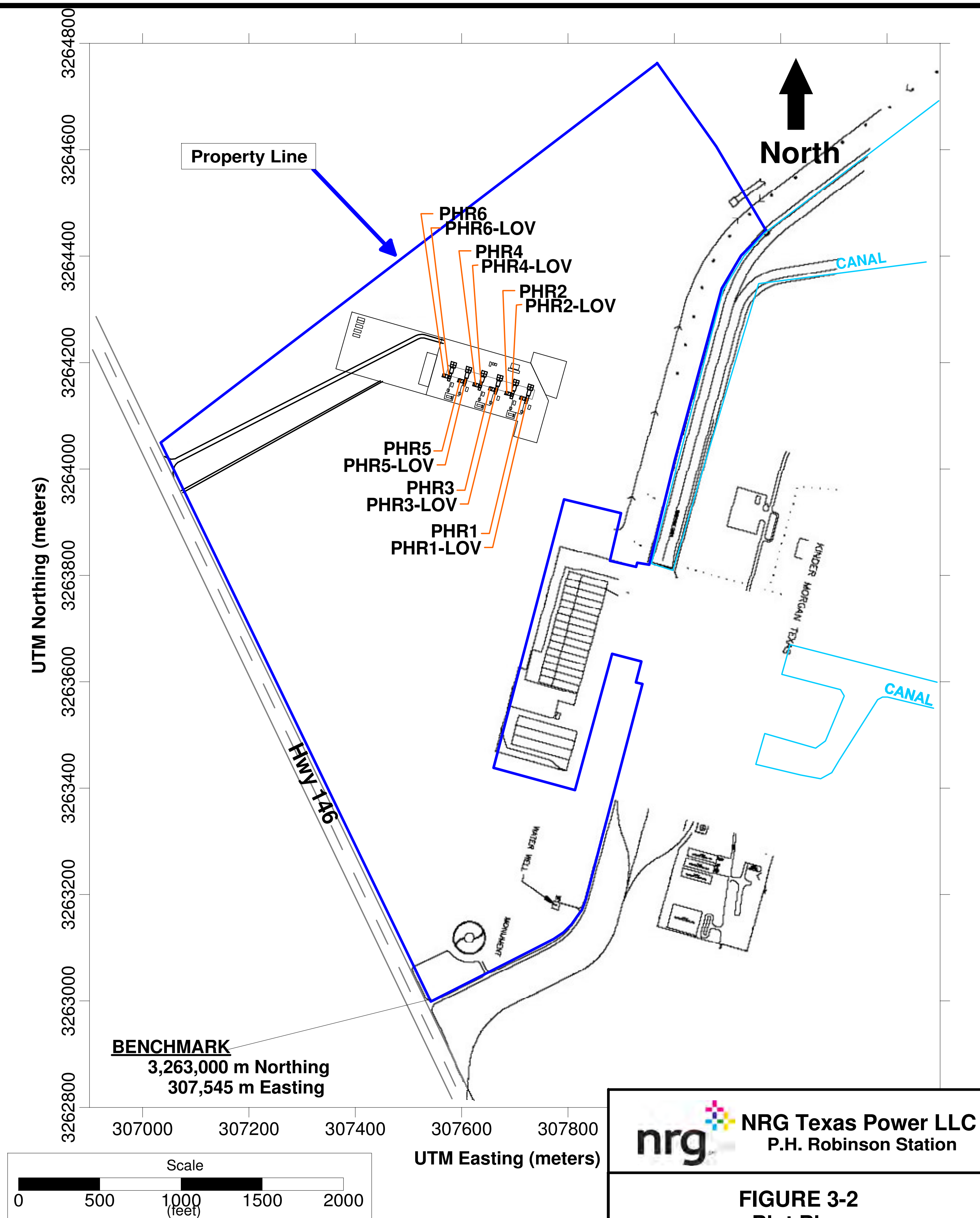
NRG Texas Power LLC
P.H. Robinson Station

FIGURE 3-1
Area Map

RPS

Ceilo Center
1250 S. Capital of Texas Highway
Building Three, Suite 200
Ausitn, Tx 78746

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



Zone: 15
Coordinate Datum: NAD 83

nrg

NRG Texas Power LLC
P.H. Robinson Station

FIGURE 3-2
Plot Plan

RPS

Ceilo Center
1250 S. Capital of Texas Highway
Building Three, Suite 200
Ausitn, Tx 78746

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 20% in any single year or 10% averaged over any three consecutive years, which qualifies the turbines as Acid Rain Peaking Units.

4.2 Gas Turbines

Each GT has an ISO rating of 65 MW but can generate up to a nominal 80 MW of power each at an ambient temperature of 10^{o}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.

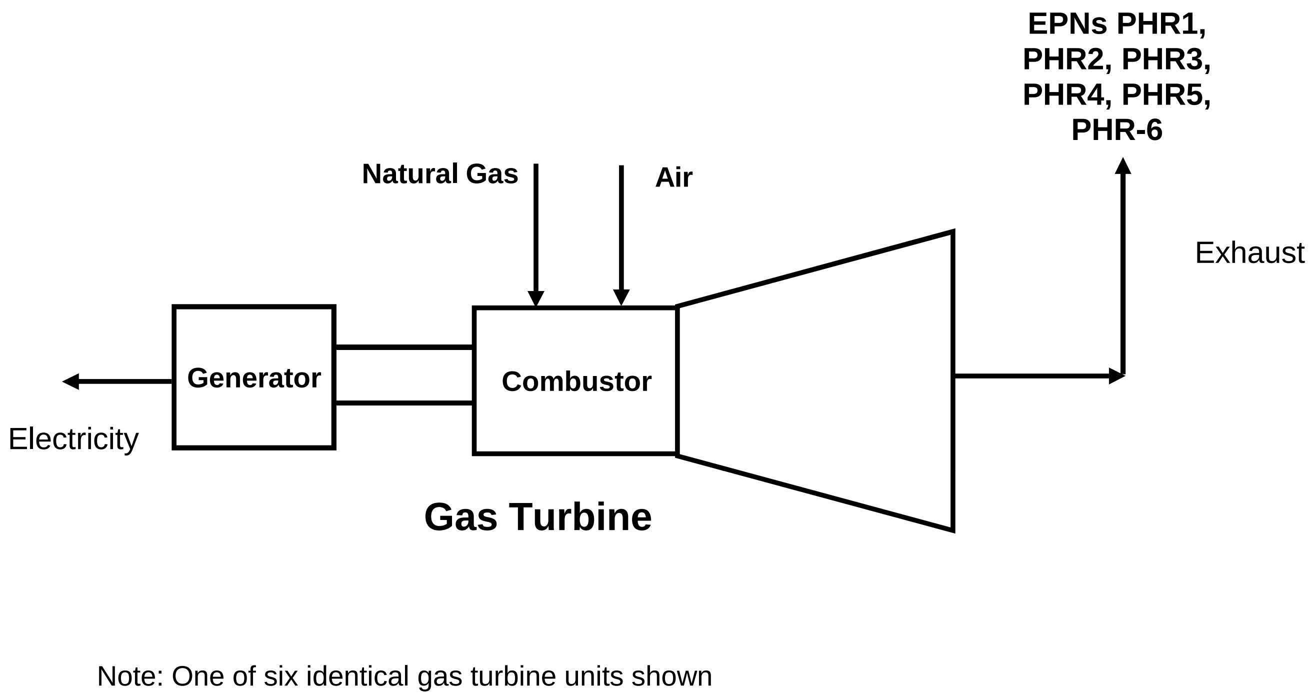


Figure 4-1
NRG Texas Power LLC
P.H. Robinson Station
Process Flow Diagram
Simple Cycle Peaking Plant

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^{o}F) and 75% relative humidity. Annual emission rates were calculated based on 1,752 hours per year (20% annual capacity factor) at these conditions. Actual operating hours may exceed 1,752 hours per year, but the total firing rate will not exceed the equivalent of 1,752 hours per year at the rated capacity of each turbine. The annual capacity factor of each turbine will not exceed 10% when averaged over three consecutive years. Although no emission limits are proposed for an averaging period longer than three years, this will result in long term (3 years or longer) GHG emissions that will average no more than half of the proposed annual limits.

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 counted toward total emissions in assessing compliance with the proposed annual CO_2e emission limits.

5.2 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.

5.3 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.

5.4 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	91,611
PHR2	Combustion Turbine 2	91,611
PHR3	Combustion Turbine 3	91,611
PHR4	Combustion Turbine 4	91,611
PHR5	Combustion Turbine 5	91,611
PHR6	Combustion Turbine 6	91,611
FUG	Fugitives	384
MSS-Fug	Gaseous Fuel Venting	158
INS-FS6	SF6 from Circuit Breakers	27
Total		**550,235**

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 facilities associated with the project that emit GHGs include six natural gas fired combustion turbines, natural gas pipeline fugitives and venting for maintenance purposes, and SF_6 emissions from circuit breakers. This BACT analysis addresses these emission sources.

The U.S. EPA-preferred methodology for a BACT analysis for pollutants and facilities subject to PSD review is described in a 1987 EPA memo (U.S. EPA, Office of Air and Radiation Memorandum from J.C. Potter to the Regional Administrators, December 1, 1987). This methodology is to determine, for the emission source in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. In addition, a control technology must be analyzed only if the applicant opposes that level of control.

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 the top-down 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.

- *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,
- 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 the remaining efficiency improvement options 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 \$107 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 \$53,000,000 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.

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 to 20% 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. 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 6.1.3 and are considered an effective means of control for the proposed turbine configuration.

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.
- *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 1,600 lbs of CO_2e per MWH (gross), based on a rolling 365-day average. This limit reflects summertime efficiency conditions, which is the peak power demand period in southeast Texas.

- NRG Texas will limit total annual emissions of CO_2e to 91,611 tpy per turbine, based on a rolling 365-day average.

6.2 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.

6.2.1 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.

6.2.2 Step 2 – Elimination of Technically Infeasible Alternatives

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

6.2.3 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%.

6.2.4 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.

6.2.5 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.

6.3 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 occur frequently, the segment of pipeline isolated for these activities is small, resulting in minimal emissions of CH_4. On the other hand, occasionally 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.

6.4 SF_6 Emissions from Electrical Equipment Insulation

6.4.1 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.

6.4.2 Step 2 – Elimination of Technically Infeasible Alternatives

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

6.4.3 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.

6.4.4 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.

6.4.5 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	494,701	\$50,954,156
CO_2 Transport Facilities (Table 6-2)	\$3.61	494,701	\$1,786,457
CO_2 Storage Facilities	\$0.51	494,701	\$252,297
Total CCS System Cost	\$107	494,701	\$52,992,911
Proposed Plant Cost	**Total Capital Cost**	**Capital Recovery Factor[4]**	**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 si turbines.

4. 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	$28,000,000	10-mile pipeline 36-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	**$28,000,000**	
Capital Recovery Factor[1]	0.0944	7% interest rate and 20 year equipment life
Annualized Capital Cost ($/yr)	**$2,643,002**	Total capital cost times capital recovery factor
Operating Cost:		
Power Cost, $/year	$4,899,249	10000 hp electric compressor and $0.075/kwh electricity cost
O&M Cost, $/year	$2,000,000	O&M estimate
Total Annual Operating Cost ($/yr)	**$6,899,249**	
Total Cost:		
Total Annual Cost ($/yr)	**$9,542,251**	Annualized capital cost plus annual operating cost
GHG Emissions Controlled (ton/yr)	2,642,412	From GHG Calculations in Appendix A
Cost Effectiveness ($/ton)	**$3.61**	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):	36

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	$8,944,802	Materials = $\$64,632 + \$1.85 \times L \times (330.5 \times D^2 + 686.7 \times D + 26,960)$
Labor	$13,096,715	Labor = $\$341,627 + \$1.85 \times L \times (343.2 \times D^2 + 2,074 \times D + 170,013)$
Miscellaneous	$5,052,053	Misc. = $\$150,166 + \$1.58 \times L \times (8,417 \times D + 7,234)$
Right-of-Way	$654,757	Right-of-Way = $\$48,037 + \$1.20 \times L \times (577 \times D + 29,788)$
Total Cost of Pipeline	**$27,748,327**	

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 limt not included in permit application
El Paso Electric CompanyMontana 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	Application submitted in Feb 2011	GE 7FA.05	207 MW	1,299	Proposed limits
		GE 7FA.04	181 MW	1,310	
		SGT6-5000F(4)	197 MW	1,278	
		GE LMS100	197 MW	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
NRG Texas Power LLC P.H. Robison Station Bacliff, Texas	Project proposed by this application	GE 7E	80 MW	1,600	Proposed limit

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

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	21
N2O	310

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	1,523,829,917	91,519	1.78	0.18	91,611
PHR2	PHR2	Combustion Turbine 2	921.67	1,523,829,917	91,519	1.78	0.18	91,611
PHR3	PHR3	Combustion Turbine 3	921.67	1,523,829,917	91,519	1.78	0.18	91,611
PHR4	PHR4	Combustion Turbine 4	921.67	1,523,829,917	91,519	1.78	0.18	91,611
PHR5	PHR5	Combustion Turbine 5	921.67	1,523,829,917	91,519	1.78	0.18	91,611
PHR6	PHR6	Combustion Turbine 6	921.67	1,523,829,917	91,519	1.78	0.18	91,611
FUG-NGAS	FUG-NGAS	Fugitives	-	-	0.00	18	0	384
FUG-MSS	FUG-MSS	Gaseous Fuel Venting	-	-	0.00	8	0	158
INS-FS6	INS-FS6	SF6 from Circuit Breakers	-	-	-	-	-	27
TOTAL								**550,235**

Notes:

Equation 98.33(a)(1): CO2, metric tons/yr = $1x10^{-3}$ x scf/yr x 1.028 MMBtu/scf $x10^{-3}$ x 53 kgCO2/MMbtu

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

Natural Gas Heating Value: 1,060 btu/scf (hhv)
Operating Hours 1,752 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:		23,900	
Annual Emission Rate (CO2 Equivalent):		**26.9**	**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)		Length	Volume[1]	Press.	Temp.	Press.	Temp.	Volume[2]	Wt	Wt	Frequency	Annual
	nom.	act.	(ft)	(ft^3)	(psig)	(°F)	(psig)	(°F)	(scf)	(lbs)	(lbs)	(per yr)	(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)		Length	Volume[1]	Press.	Temp.	Press.	Temp.	Volume[2]	Wt	Wt	Frequency	Annual
	nom.	act.	(ft)	(ft^3)	(psig)	(°F)	(psig)	(°F)	(scf)	(lbs)	(lbs)	(per yr)	(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

Appendix B
NRG Robinson Peaking Units
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-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	COMBUSTION TURBINE GENERATOR	154 MW	Carbon Dioxide Equivalent (CO2e)	None identified	774 LB/MW-HR
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	4/20/2012	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	227,840 TPY
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	511,429 522,772 601,520 681,839 TPY
Region 6	South Texas Elecric Cooperative Inc. Red Gate Power Plant	TX	01/02/13	Simple Cycle Recipricating Engine peaking plant 12 RICE at 18.75 MW each	225 MW	Carbon Dioxide Equivalent (CO2e)	energy-efficient SI RICE	1,193 lb CO2/MWh
*CA-1212	PALMDALE HYBRID POWER PROJECT	CA	10/18/2011	ENCLOSED PRESSURE SF6 CIRCUIT BREAKERS	0	Carbon Dioxide Equivalent (CO2e)	None identified	9.56 TPY
Region 6	El Paso Electric Company Montana Power Station	TX	4/20/2012	ENCLOSED PRESSURE SF6 CIRCUIT BREAKERS	0	Carbon Dioxide Equivalent (CO2e)	Use of state-of-the-art circuit breakers that are gas-tight; Implementing an LDAR program to identify and repair leaks	335 TPY
Region 6	ExTex LaPorte, LP Mountain Creek Steam Electric Station	TX	11/30/12	ENCLOSED PRESSURE SF6 CIRCUIT BREAKERS	0	Carbon Dioxide Equivalent (CO2e)	Implement modern state state-of-the-art, gas-tight circuit breakers; an inspection and maintenance program	16.73 TPY
Region 6	Guadalupe Power Partners LP Guadalupe Generating Station	TX	11/12/12	ENCLOSED PRESSURE SF6 CIRCUIT BREAKERS	0	Carbon Dioxide Equivalent (CO2e)	state-of-the-art enclosed pressure SF6 circuit breakers	82.5 TPY

Search date: 1/1/2013

Appendix B
NRG Robinson Peaking Units
RBLC and USEPA Region 6 Database Search Results for GHG Emissions from Circuit Breakers

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT DATE	PROCESS_NAME	THROUGHPUT	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	0	Carbon Dioxide Equivalent (CO2e)	enclosed-pressure SF6 circuit breakers with an annual leakage rate of 0.5% by weight equipped with a leak detection system	23.9 TPY
*FL-0330	PORT DOLPHIN ENERGY LLC	FL	12/01/2011	Fugitive GHG emissions	0	Carbon Dioxide	a gas and leak detection system will be used.	0
LA-0257	SABINE PASS LNG TERMINAL	LA	12/06/2011	Fugitive Emissions	0	Carbon Dioxide Equivalent (CO2e)	conduct a leak detection and repair (LDAR) program	89629 TONS/YR
Region 6	El Paso Electric Company Montana Power Station	TX	4/20/2012	Fugitive Emissions	0	Carbon Dioxide Equivalent (CO2e)	Implement a AVO program will be used to detect any leaks	94 TPY
Region 6	ExTex LaPorte, LP Mountain Creek Steam Electric Station	TX	11/30/12	Fugitive Emissions	0	Carbon Dioxide Equivalent (CO2e)	Implement AVO LDAR	7.64 TPY
Region 6	Guadalupe Power Partners LP Guadalupe Generating Station	TX	11/12/12	Fugitive Emissions	0	Carbon Dioxide Equivalent (CO2e)	None identified	42.7 TPY

Search date: 1/1/2013