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June 25, 2014 *SENT VIA ELECTRONIC MAIL and USPS*

Mr. Jeff Robinson
Chief, Air Permit Section
U.S. EPA Region 6, 6PD-R
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

RE: Apex Texas Power, LLC
Proposed Electric Generating Facility; Cherokee County, TX
Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) Permit Application

Dear Mr. Robinson,

Sage Environmental Consulting, L.P. (Sage) is pleased to submit the enclosed GHG PSD permit application to the U.S. EPA on the behalf of Apex Texas Power, LLC (Apex). Apex proposes to construct a new electric generating facility near Cuney, TX in Cherokee County. The facility design and permit application include two construction scenarios: Scenario 1 for a 4-turbine simple cycle peaking plant; and, Scenario 2 for a combined cycle, cogeneration plant.

Scenario 1 will be utilized solely for electric peaking operation. The plant will have a total power generation output capacity of approximately 930 megawatts (MW) gross. Scenario 2 has a two-phase approach to the facility construction. Phase 1 for simple cycle operation of two turbines and Phase 2 for a combined cycle, cogeneration plant. Upon completion of Phase 2 the facility will have a nominal generation capacity of 794 MW. The facilities will include two combustion gas turbines (Phase 1) with the option to install two heat recovery steam generators, a steam turbine, and associated ancillary process equipment.

Understanding that the Texas Commission on Environmental Quality (TCEQ) and U.S. EPA are in the process of promulgating rules to transfer the GHG PSD permitting authority from EPA Region 6 to the TCEQ, the enclosed permit application is also being sent to the TCEQ Air Permits Division. A PSD permit application for the remaining non-GHG criteria pollutants will be submitted to the TCEQ for their review, with a copy sent to EPA Region 6. The non-GHG permit application is expected to be submitted in approximately one week. Due to the expected delegation of the GHG PSD program to the TCEQ in the near future, Apex respectfully requests that the TCEQ complete the review of the GHG permit application and issue the GHG PSD permit upon completion of the review process.

12727 FEATHERWOOD DR., SUITE 210 • HOUSTON, TEXAS • 77034 • 282/484-6200 • FAX 281/484-6201

Sage appreciates your attention to the enclosed application and looks forward to working with EPA Region 6 and the TCEQ to assist Apex in the successful development of this project. Please do not hesitate to call me at (713) 539-6954 or to contact me via email at faheem.kazimi@sageenvironmental.com if you have any questions regarding this application.

Sincerely,
Sage Environmental Consulting, L.P.

Faheem Kazimi
Client Guardian

Enclosure

cc: Mr. Mike Wilson, TCEQ, Air Permits Division Director, 12100 Park 35 Circle, Austin, TX 78753
Mr. David Jenkins - Apex (electronic)
Mr. Michael King - Apex (electronic)

APEX Texas Power, LLC

Prevention of Significant Deterioration Permit Application for Greenhouse Gas Emissions

Neches Station
Cherokee County, Texas

June 2014

Prepared by

SAGE
ENVIRONMENTAL CONSULTING

TABLE OF CONTENTS

TABLE OF CONTENTS – (CONTINUED)

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

SECTION 1
INTRODUCTION

1.1 Introduction

Apex Texas Power, LLC (Apex) is hereby submitting this application for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) air quality permit for the construction of the Neches Station, a greenfield electric generating station and ancillary equipment, located near Cuney, in Cherokee County, Texas. The primary Standard Industrial Classification code of the proposed Neches Station is 4911 (Electric Services). Apex has not yet been assigned a Customer Number (CN) by the Texas Commission on Environmental Quality (TCEQ). The Neches Station has not yet been assigned a TCEQ Regulated Entity Number (RN).

The proposed Neches Station will be a new major source with respect to GHG emissions and subject to PSD permitting requirements currently administered by the U.S. Environmental Protection Agency (EPA) Region 6. The permitting authority of GHG emissions in Texas is being transferred to TCEQ; however, the transition from the EPA Region 6 to the TCEQ has not been completed. Therefore, a GHG PSD permit application is being submitted to the EPA Region 6 for review and approval until the TCEQ has been delegated full authority to issue GHG permits. Accordingly, Apex is submitting applications to both agencies (EPA Region 6 and TCEQ) to obtain the authorizations to construct the Neches Station. Once TCEQ is the GHG permitting authority, Apex will request the permit application be transferred to the TCEQ. This document constitutes Apex's application for the required GHG PSD permit. A separate application is being submitted concurrently to the TCEQ for non-GHG pollutants.

1.2 Project Scope

Apex proposes the following two design scenarios for the Neches Station:

- *Scenario 1* – The plant will consist of four (4) combustion turbine generators (CTGs) operating in simple cycle mode with a total power generation output capacity of approximately 930 megawatts (MW) gross.
- *Scenario 2* – The plant will consist of two (2) units that will be constructed in two phases:
    - Phase 1: Two CTGs will be constructed and operated in a simple cycle mode until the construction of the heat recovery steam generators (HRSGs) and the steam turbine is completed, at which time the units can operate in combined cycle mode; and
    - Phase 2: Following startup of the HRSGs and the steam turbine, the capability to operate the combustion turbines in a simple cycle mode will be retained for operational flexibility depending on market demands. The total power generation output capacity of Phase 2 is approximately 794 MW gross.

A detailed process description is included in Section 4 of this permit application.

1.3 Application Contents

The application is organized as follows:

- Federal GHG Permitting Applicability is included in Section 2.
- An area map and plot plans detailing the facility location and locations of all emission points with respect to the plant property are included in Section 3.
- The project description, the process description and process flow diagrams are included in Section 4.
- Information on the basis of calculations and proposed GHG limits is included in Section 5.
- A Best Available Control Technology (BACT) analysis for the new GHG emission sources is included in Section 6.
- Adherence to additional PSD requirements is explained in Section 7.
- Information about proposed GHG monitoring provisions is contained in Section 8.
- GHG emission calculations are included in Appendix A.

SECTION 2
FEDERAL GHG PERMITTING APPLICABILITY

The Neches Station is a new major source for GHG emissions since it has a PTE for GHGs greater than 100,000 TPY on a CO_2 equivalent (CO_2e) basis and greater than 100 TPY on a mass basis. GHG emissions from the proposed Neches Station including carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6) are provided in the following table and are expressed as CO_2e.

Under the GHG Tailoring Rule issued in May 2010, GHG emissions from the largest stationary sources will be covered by the PSD rule beginning January 2, 2011. Specifically under Step 2 of this rule PSD applies to the GHG emissions from a proposed new major source if the following is true for GHG PSD permits issued on or after July 1, 2011:

- The potential-to-emit (PTE) for GHGs from the new source would be equal to or greater than 100,000 TPY on a CO_2e basis ***and*** equal to or greater than 100/250 TPY (depending on the source category) on a mass basis.

As shown on Table 1-1, the project increase in GHG emissions expressed as CO_2e is greater than 100,000 TPY; and therefore, the project triggers a PSD review for GHG emissions.

Table 1-1 Project GHG Emission Summary

POLLUTANT*	PROJECTED MAXIMUM ANNUAL GHG EMISSION TPY
CO_2, CH_4, N_2O, SF_6 expressed as CO_2e	3,208,472

* Note: No other emissions of GHG regulated pollutants (hydrofluorocarbons (HFCs), nor perfluorocarbons (PFCs)) are emitted as part of the Neches Station.

The following administrative forms are included in this section:

- TCEQ Table 1F; and
- TCEQ Table 2F.

Tables 1F and 2F are TCEQ's federal NSR applicability forms. Because this application covers only GHG emissions, and permitting of other pollutants is being submitted under a separate application to be reviewed by the TCEQ, these forms only include GHG emissions.

In addition, annual GHG emissions from the Neches Station will be the highest under Scenario 2 Phase 2 combined cycle mode; therefore, for a conservative permitting basis, only annual GHG emissions from Scenario 2 Phase 2 combined cycle mode are used in the PSD applicability determination.

TCEQ

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: **TBD**	Application Submittal Date: **June 2014**						
Company: **Apex Texas Power, LLC**							
RN: **TBD**	Facility Location: Approximately **1 mile southeast of Cuney, TX**						
City: **Cuney**	County: **Cherokee**						
Permit Unit I.D.: **Neches Power Station**	Permit Name: **TBD**						
Permit Activity: **X** New Source Modification							
	POLLUTANTS						
Complete for all Pollutants with a Project Emission Increase.	**Ozone**		**CO_2e**				**Other** [1]
	VOC	**NO_X**					
Nonattainment?			NO	-	-	-	-
PSD?							
Existing site PTE (tpy)?			-	-	-	-	-
Proposed project emission increases (tpy from 2F[2])?			3,208,472	-	-	-	-
Is the existing site a major source?			-	-	-	-	-
If not, is the project a major source by itself?			YES	-	-	-	-
If site is major source, is project increase significant?			YES	-	-	-	-
If netting required, estimated start of construction: **Not Required**							
5 years prior to start of construction contemporaneous: **Not Applicable**							contemporaneous
Estimated start of operation period: **2017 Q3**							period
Net contemporaneous change, including proposed project, from Table 3F. (tpy)			N/A	-	-	-	-
Major NSR Applicable?			YES	-	-	-	-

[illegible] — *Signature* Officer — *Title* 6/24/14 — *Date*

[1] Other PSD pollutants. [Pb, H_2S, TRS, H_2SO_4, Fluoride excluding HF, etc.]

[2] Sum of proposed emissions minus baseline emission, increases only.

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

TABLE 2F

PROJECT EMISSIONS INCREASE

June 2014

Pollutant(1):	**CO_2e**	**Permit:**	**TBD**
Baseline Period: N/A			

	Affected or Modified Facilities [2]		Permit No.	Actual Emissions [3]	A	B	Projected Actual Emissions	Difference (B-A) [6]	Correction [7]	Project Increase [8]
	FIN	EPN			Baseline Emissions [4]	Proposed Emissions [5]				
1	CTG1/HRSG1/DB1 CGT2/HRSG2/DB2	E-ST1b E-ST2b	TBD	0.00	0.00	3,201,088	3,201,088	3,201,088	0.00	3,201,088
2	AUXBLR	E-AUXBLR	TBD	0.00	0.00	5,589	5,589	5,589	0.00	5,589
3	FWP	E-FWP	TBD	0.00	0.00	19	19	19	0.00	19
4	FUG-NG	FUG-NG	TBD	0.00	0.00	1,549	1,549	1,549	0.00	1,549
5	FUG-SF6	FUG-SF6	TBD	0.00	0.00	228	228	228	0.00	228
								Page Subtotal(9)		3,208,472

[1] Individual Table 2Fs should be used to summarize the project emission increase for each criteria pollutant
[2] Emission Point Number as designated in NSR Permit or Emissions Inventory
[3] All records and calculations for these values must be available upon request
[4] Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement
[5] If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement
[6] Proposed Emissions (column B) minus Baseline Emissions (column A)
[7] Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement
[8] Obtained by subtracting the correction from the difference. Must be a positive number.
[9] Sum all values for this page.

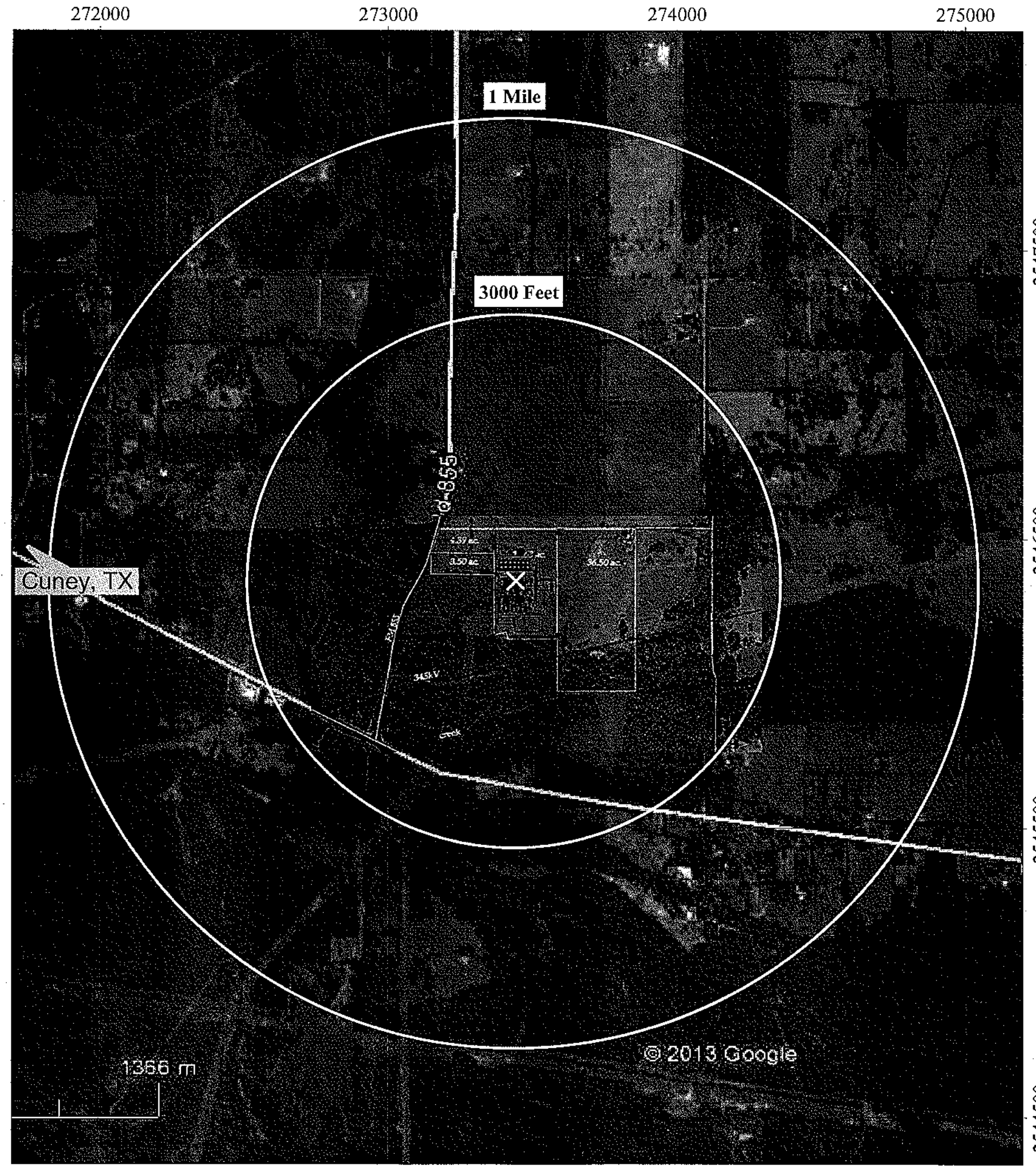
TCEQ - 20470 (Revised 04/12) Table 2F

These forms are for use by facilities subject to air quality permit requirements and may be revised periodically. (APDG 5915v2)

Page 1 of 1

SECTION 3
AREA MAP AND PLOT PLAN

An area map showing the general location of the Neches Station and a 3,000-foot radius and a one-mile radius is included as Figure 3-1. Figure 3-2 presents the layout of major equipment of Scenario 1 – Peaking Units at the Neches Station. Figure 3-3 presents the layout for the 2x2x1 configuration of Scenario 2 Phase 2 (combined cycle mode) of the Neches Station. Figure 3-3 also shows the emission point numbers (EPNs) E-ST1a and E-ST2a for Scenario 2 simple cycle mode.



SCALE (meters)

0 250 500 750 1000

NORTH

UTM Zone 14
NAD83

FIGURE 3-1
SITE LOCATION ON AERIAL PHOTO
Neches Electric Generating Plant
Near Cuney in Cherokee County, TX

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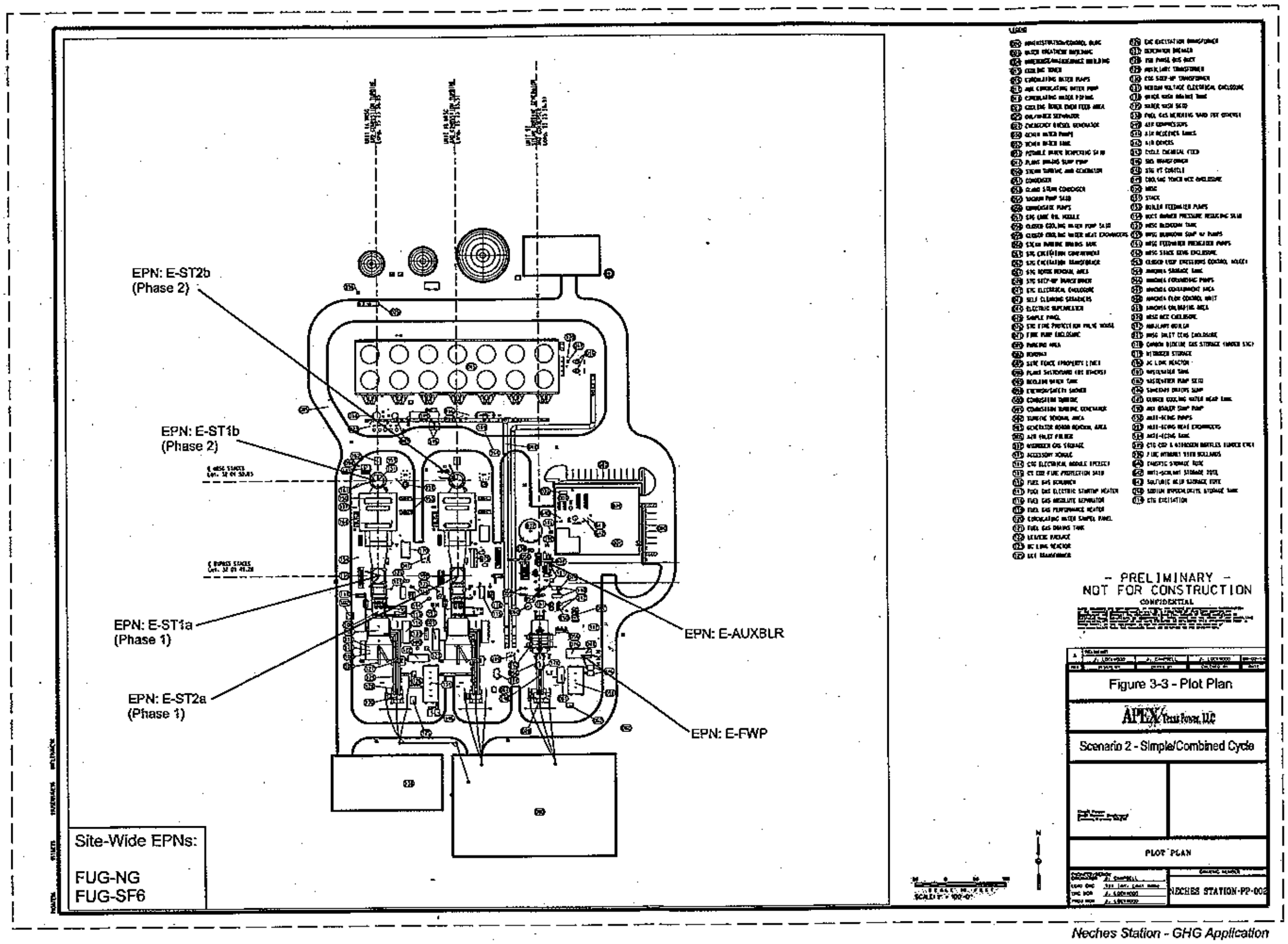
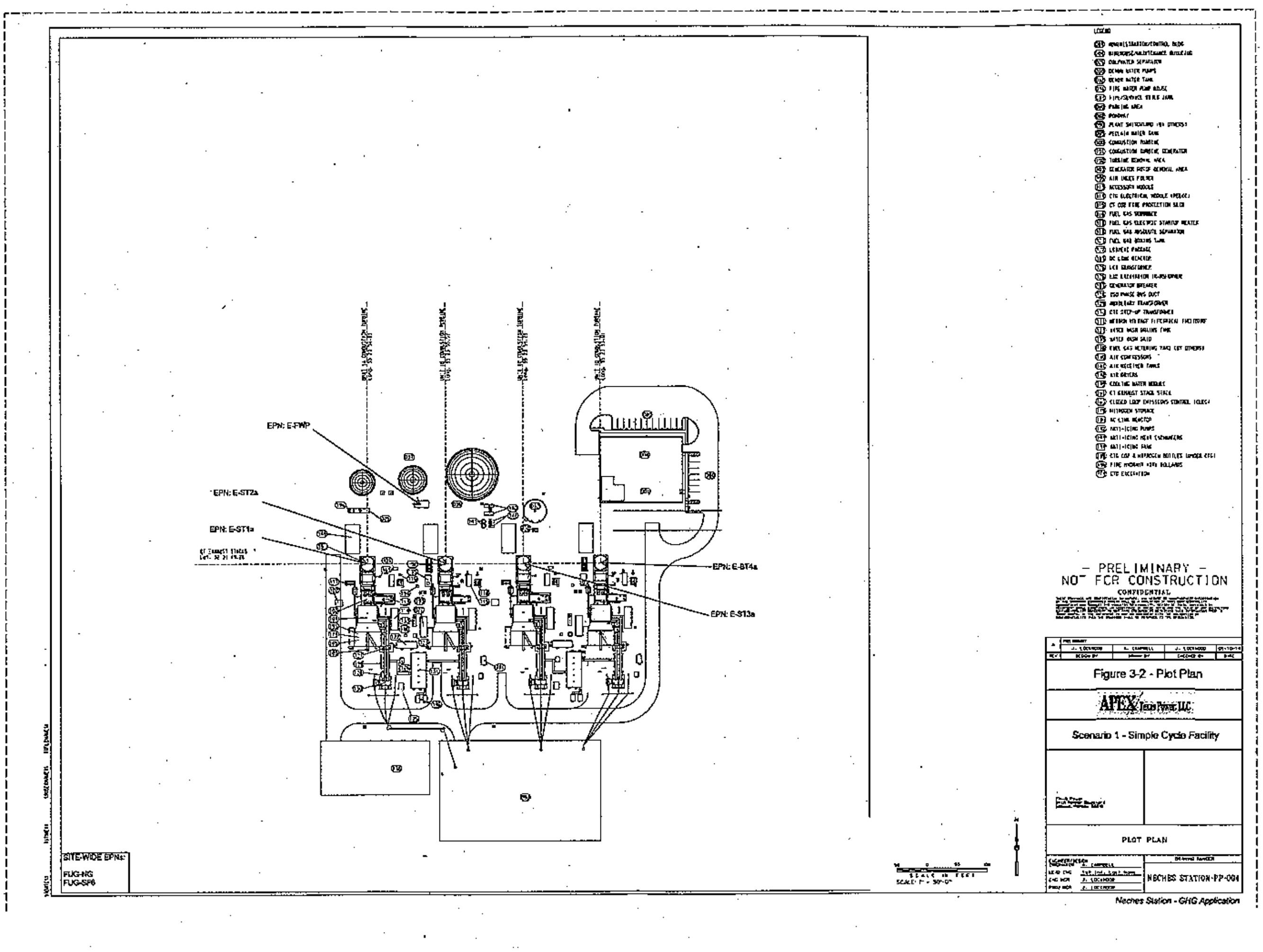
"Friendly Service, No Surprises!"

DATE: June 2014	
PROJECT: 1359-1-1-4-1	
FILE NAME: Neches Site Map.srf	



EPN: E-ST2b
(Phase 2)
EPN: E-ST1b
(Phase 2)
EPN: E-ST1a
(Phase 1)
EPN: E-ST2a
(Phase 1)
EPN: E-AUXBLR
EPN: E-FWP
Site-Wide EPNs:
FUG-NG
FUG-SF6
- PRELIMINARY -
NOT FOR CONSTRUCTION
CONFIDENTIAL
Figure 3-3 - Plot Plan
APEX Texas Power, LLC
Scenario 2 - Simple/Combined Cycle
PLOT PLAN
NECHES STATION-PP-002



EPN: E-FWP
EPN: E-ST2a
EPN: E-ST1a
EPN: E-ST4a
EPN: E-ST3a
SITE-WIDE EPNs:
FUG-NG
FUG-SF6
- PRELIMINARY -
NOT FOR CONSTRUCTION
CONFIDENTIAL
Figure 3-2 - Plot Plan
APEX Texas Power, LLC
Scenario 1 - Simple Cycle Facility
PLOT PLAN
NECHES STATION-PP-004

SECTION 4
PROJECT DESCRIPTION AND PROCESS DESCRIPTION

This section provides the project description and process description of the proposed Neches Station, a new electric generating plant.

4.1 Project Description

Apex proposes the following two scenarios for the Neches Station:

- *Scenario 1* – The plant will consist of four (4) combustion turbine generators (CTGs) operating in simple cycle mode (peaking units) with a total power generation output capacity of approximately 930 megawatts (MW) gross. Annual operation will be limited to 2,500 hours per year per turbine.
- *Scenario 2* – The plant will consist of two units that will be constructed in two phases:
  - Phase 1: Two CTGs will be constructed and operated in a simple cycle mode until the construction of the HRSGs and the steam turbine is completed, at which time the units can operate in combined cycle mode; and
  - Phase 2: Following startup of the HRSGs and the steam turbine, the capability to operate the combustion turbines in a simple cycle mode for up to 2,500 hours per year per turbine will be retained for operational flexibility depending on market demands. The total power generation output capacity of Phase 2 is approximately 794 MW gross.

The proposed Neches Station will include the following GHG emissions sources:

Scenario 1

- Four (4) natural gas-fired combustion turbines including planned maintenance, startup, and shutdown (MSS) activities;
- One (1) diesel firewater pump engine; and
- Fugitive emissions from piping components.
- Fugitive emissions from SF_6 insulated electrical equipment.

Scenario 2

- Two (2) natural gas-fired CTGs including planned MSS activities;
- Two (2) heat recovery steam generating units equipped with natural gas-fired duct burners;
- One (1) natural gas-fired auxiliary boiler;
- One (1) diesel firewater pump engine;
- Fugitive emissions from piping components.
- Fugitive emissions from SF_6 insulated electrical equipment.

High-efficiency and low-emitting F-Class turbines are being considered for the project. Fuel to the CTGs and HRSG duct burners will be exclusively pipeline natural gas. Process flow diagrams (PFDs) for the proposed project are included at the end of this section. The PFD for Scenario 1 is shown as Figure 4-1. The PFDs for Scenario 2 with simple cycle mode and combined cycle mode are shown separately in Figures 4-2a and 4-2b, respectively.

4.2 Process Description

4.2.1 Scenario 1 – Combustion Turbine Generator

In Scenario 1, the plant will consist of up to four identical natural gas-fired CTGs with a generic F-Class turbine being selected. Each CTG will be designed to burn pipeline quality natural gas to rotate an electric generator to generate approximately 232 MW of power. The main components of a CTG consist of a compressor, combustor, turbine, and generator. The compressor pressurizes air to the combustor where it is mixed with fuel and burned. The combustor's hot exhaust gases then enter the turbine where the gases expand across the turbine blades, driving the shaft to power an electric generator. The exhaust gases will be released directly to the atmosphere. The gas turbines will be equipped with evaporative cooling to improve the efficiency and output at high ambient temperatures.

Emission point numbers (EPNs) for the CTG units in Scenario 1 (Peaking units) are identified as E-ST1a, E-ST2a, E-ST3a, and E-ST4a.

4.2.2 Scenario 2 - Combustion Turbine Generator and Heat Recovery Steam Generators

In Scenario 2, the plant will consist of two identical natural gas-fired CTGs with a generic F-Class turbine being selected. The operation of the gas combustion turbines in Scenario 2 – Phase 1 is the same as that described above in Scenario 1. In Phase 2, after the HRSGs and the steam turbine are constructed, the hot exhaust gas from each CTG can be directed to a dedicated HRSG where thermal energy will be recovered to generate steam that will be routed to the steam turbine to generate additional power.

Each HRSG will be designed to produce steam which will be used to drive a steam turbine. Each HRSG will be equipped with natural gas-fired duct burners with a firing capacity of approximately 532 MMBtu/hr (higher heating value, HHV). During simple cycle mode, the CTG exhaust will be emitted to the atmosphere through a single stack for each CTG. In full combined cycle mode, the exhaust stream from each CTG, HRSG, and duct burner will be released to the atmosphere through a single stack for each train consisting of CTG/HRSG/DB.

EPNs for the CTG units in Scenario 2 Phase 1 (simple cycle mode) are identified as E-ST1a and E-ST2a. The EPNs for the CTG/HRSG units in Scenario 2 Phase 2 (combined cycle mode) are identified as E-ST1b and E-ST2b.

4.2.3 Auxiliary Boiler

A natural gas-fired auxiliary boiler (EPN E-AUXBLR) with a rating of approximately 108 MMBtu/hr will provide turbine fast start steam requirements during periods when the combustion turbines are out of service for Scenario 2. The annual operation of the boiler will be limited to an annual heat input that is equivalent to 10% of the auxiliary boiler's maximum annual capacity.

4.2.4 Firewater Pump

The site will be equipped with one 360-hp diesel-fired firewater pump engine (EPN E-FWP) in the event of a fire or other emergency situation. The engine will fire periodically for testing, proper maintenance and to assure proper operation.

4.2.5 Natural Gas/Fuel Gas Piping

Natural gas will be delivered to the site via pipeline. Gas will be metered and piped to the combustion turbines and duct burners. Project GHG fugitive emissions from the gas piping components associated with the CTG/HRSG units will include emissions of methane (CH_4) and carbon dioxide (CO_2). The natural gas piping is designated as EPN FUG-NG.

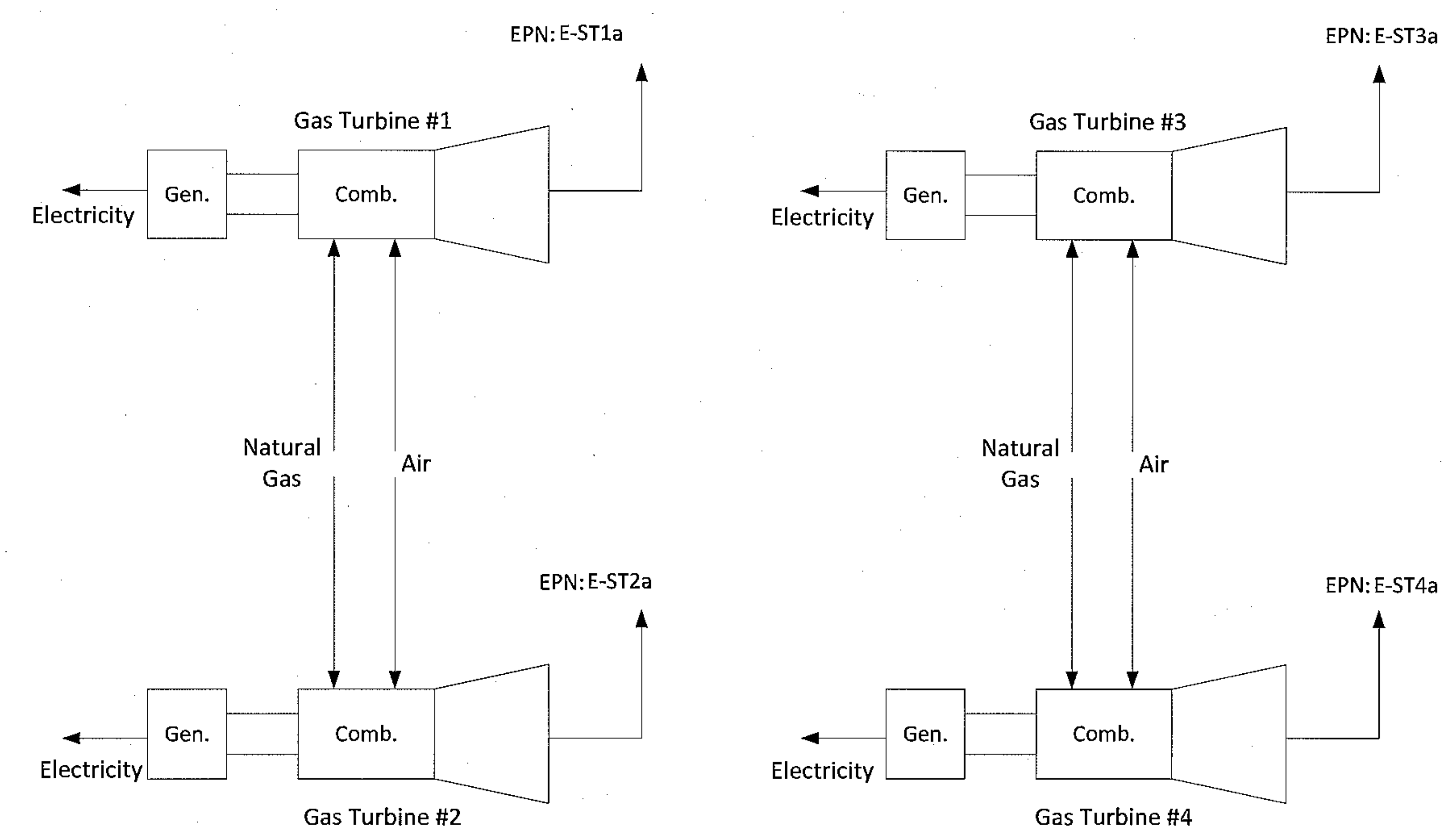
4.2.6 Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6)

The generator circuit breakers and switchyard breakers associated with the proposed units will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipments. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. The capacity of the circuit breakers and switchyard breakers associated with the proposed plant is currently estimated to be 4,000 lbs of SF_6.

The proposed circuit breakers and switchyard breakers will have a low pressure alarm and a low pressure lockout. The alarm will alert operating personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF_6 gas.

4.2.7 Turbine Startup and Shutdown

In order to meet peak demands in power, the combustion turbines will require frequent startup and shutdown (SUSD). The details of the SUSD activities and the duration are provided in the calculations in Appendix A.



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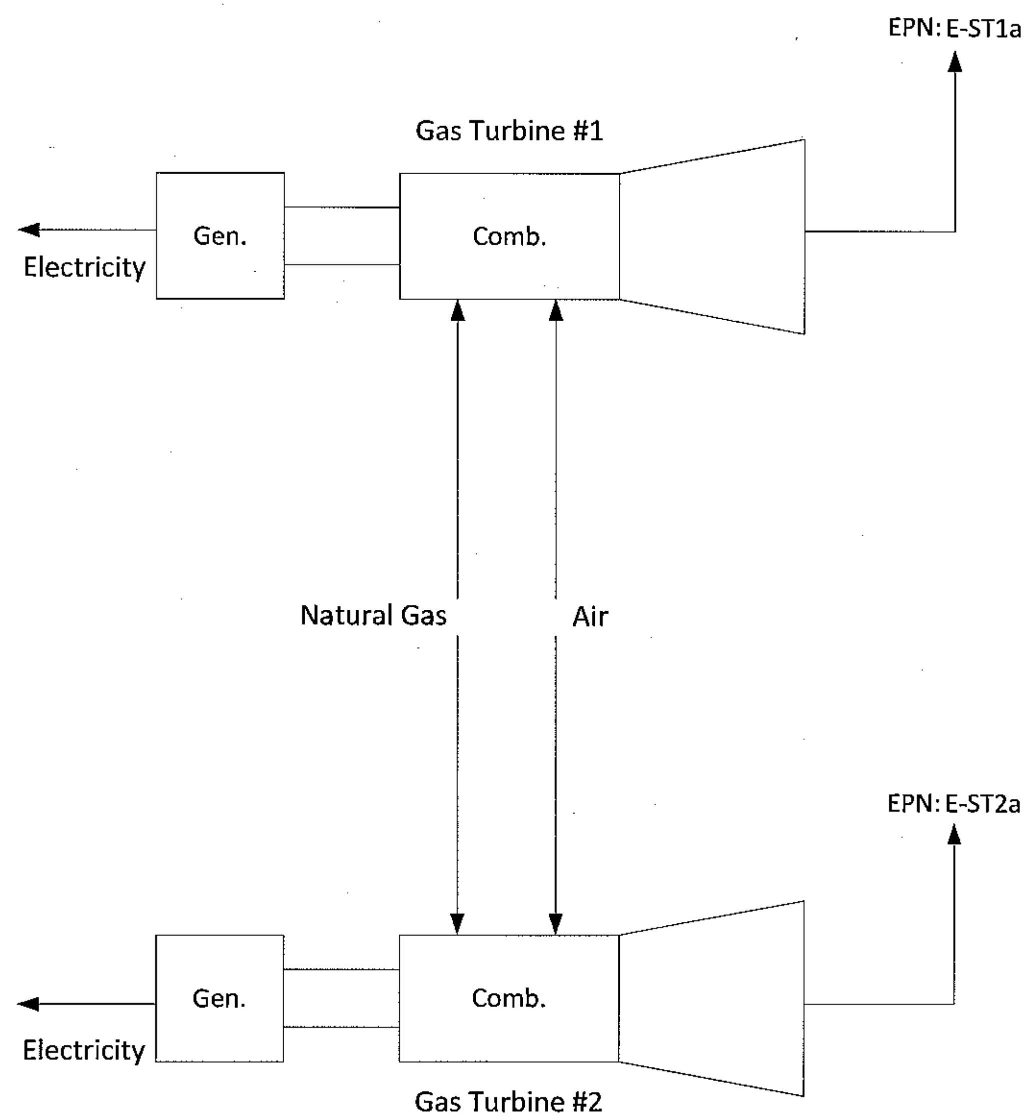
Process Flow Diagram

Figure 4-1

Scenario 1- Peaking Units



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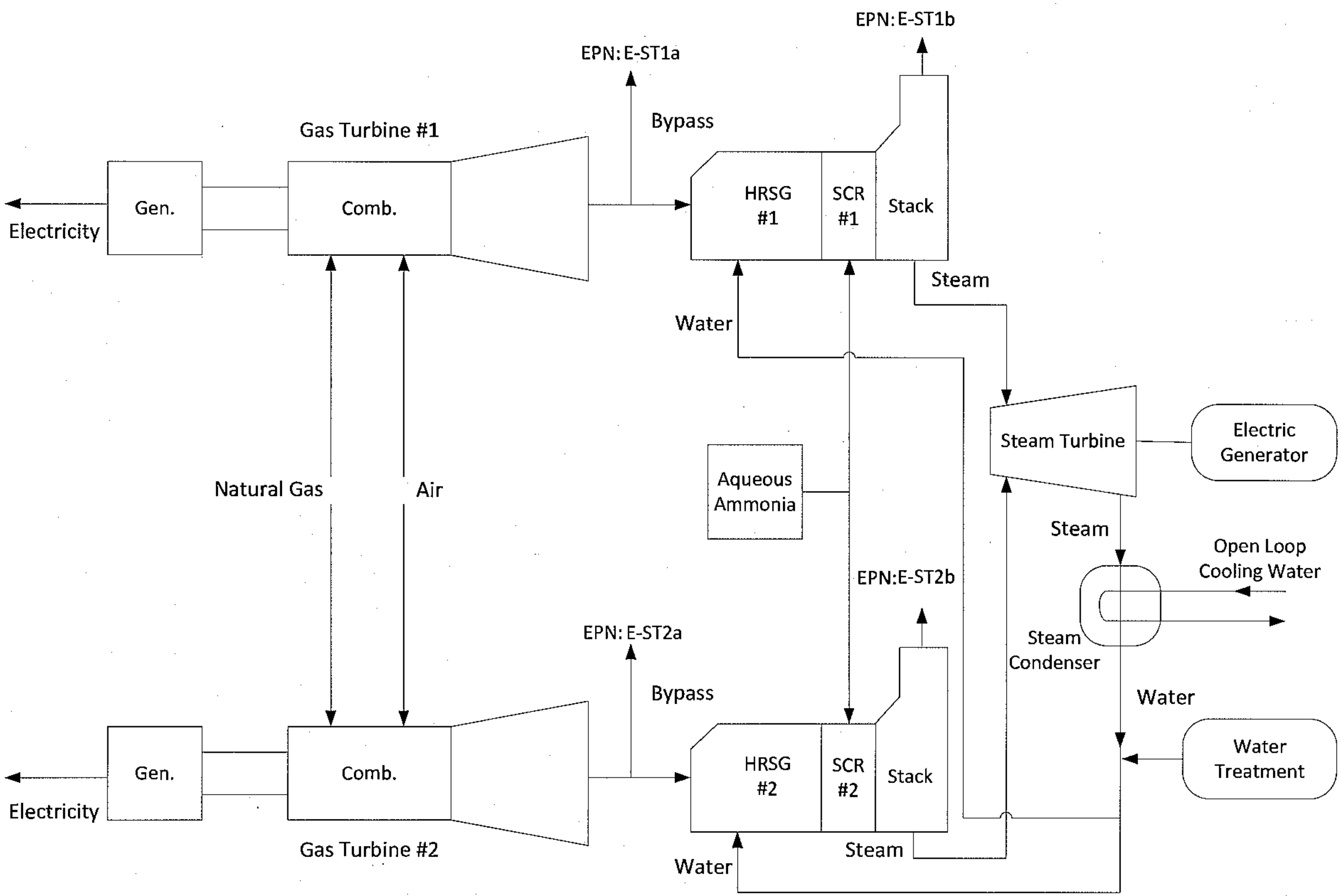
Process Flow Diagram

Figure 4-2a

Scenario 2-Phase 1 (Simple Cycle Mode)



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Process Flow Diagram

Figure 4-2b

Scenario 2-Phase 2 (Combined Cycle Mode)

SECTION 5
EMISSION RATE CALCULATION BASIS

This section contains a description of the GHG emissions generated from the equipment associated with the project. GHG emission calculations methods are also described, and the resulting GHG emission rates are presented in Appendix A. Since turbines' performance will vary with the ambient temperature, relative humidity, and load conditions, the values presented in this application are best engineering estimates based on worst case scenarios of the currently proposed design scenarios. These may be changed with final design that is chosen, but will not exceed those emission values represented in this application.

5.1 Gas Turbines and Duct Burners

GHG emissions for the combustion turbines and HRSG duct burners were evaluated and calculated in accordance with the procedures in the Mandatory Greenhouse Reporting Rules, Title 40 Code of Federal Regulations (40 CFR), Part 98, Subpart D – Electricity Generation. Annual CO_2 emissions were calculated in according with equation G-4 of the Acid Rain Rules, 40 CFR Part 75, Appendix G – Determination of CO_2 Emissions (as required by Part 98, Subpart D).

$$W_{CO_2} = \left(\frac{F_C * H * U_f * MW_{CO_2}}{2000}\right)$$

Where:

W_{CO2} = CO_2 emitted from combustion, tons/yr.

MW_{CO2} = Molecular weight of carbon dioxide, 44.0 lb/lb-mole.

F_C = Carbon based F-factor, 1040 scf/MMBtu for natural gas.

H = Annual heat input in MMBtu.

U_f = 1/385 scf CO_2/lb-mole at 14.7 psia and 68 °F.

The annual heat input, H, was calculated based on the maximum total power output in MWh multiplied by the maximum cycle heat rate for all appropriate cases. These values were based on design information from the power engineering consultants with margins added as follows:

- 3.3% design margin as a contingency in turbine design heat rate.
- 6.0% performance margin to account for efficiency losses due to equipment degradation prior to maintenance overhauls.

- 3.0% degradation margin to account for the variability in operation of the auxiliary plant equipment due to use over time.

Emissions of CH_4 and N_2O were calculated in accordance with the emission factors for natural gas combustion from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules, 40 CFR Part 98, Subpart C. The emissions rates of each GHG were then converted to CO_2e emissions using the global warming potential (GWP) factors from Table A-1 of 40 CFR Part 98, Subpart A.

Turbine startup and shutdown emissions were calculated based on estimated hours per year of startup/shutdown activities and the estimated power output and heat rate at lower loads.

5.2 Auxiliary Boiler

The auxiliary boiler will be fired with pipeline natural gas. Emissions were calculated by multiplying the appropriate emission factor by the estimated maximum annual firing. Emissions of CO_2, CH_4, and N_2O were calculated using emission factors from Tables C-1 and C-2 of 40 CFR Part 98, Subpart C for natural gas combustion. The emissions rates of each GHG were then converted to CO_2e emissions using the GWP factors from Table A-1 of 40 CFR Part 98, Subpart A. The auxiliary boiler will not be utilized on a continuous basis; therefore, its annual GHG emissions were calculated based on 94,958.4 MMBtu/yr which is equivalent to 10% of the maximum annual capacity of the auxiliary boiler.

5.3 Firewater Pump

CO_2 emission calculations from the diesel-fired firewater pump engine were calculated using the emission factors for Distillate Fuel Oil No. 2 from Table C-1 of 40 CFR Part 98, Subpart C. CH_4 and N_2O emissions from the diesel-fired engine were calculated using the emission factors for Petroleum from Table C-2 of 40 CFR Part 98, Subpart C. The GWP factors used to calculate CO_2e emissions are from Table A-1 of 40 CFR Part 98, Subpart A.

5.4 Natural Gas Pipeline Fugitives

Potential fugitive emissions of CH_4 and CO_2 are anticipated from piping components in the natural gas fuel lines that provide fuel to the combustion turbines and duct burners. Each fugitive component was classified first by equipment type (valve, flange, relief valve, etc.) and then by fluid 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 factor for Western U.S. from Table W-1A of 40 CFR Part 98. No control credit was applied for the natural gas fuel lines although periodic walk through inspections of lines will be made. The CH_4 emission rates were established by multiplying the total emission rates by the concentration (weight %) of CH_4 in the natural gas. The CO_2 emission rates were established by multiplying the total emission rates by the concentration (weight %) of CO_2 in the natural gas. The CH_4 and CO_2 emissions rates were then converted to CO_2e emissions using their respective GWP factor from Table A-1 of 40 CFR Part 98, Subpart A.

5.5 SF_6 Emissions from Electrical Equipment Insulation

Emissions of sulfur hexafluoride (SF_6) due to potential leaks from the insulation used in general circuit breakers and switchyard breakers were estimated by applying a 0.5% annual leak rate to the weight of SF_6 estimated to be present in insulated equipment associated with the new facilities. This is the current maximum leak rate standard established by the International Electrical Commission (IEC). The SF_6 emissions rate was then converted to CO_2e emissions using its corresponding GWP factor from Table A-1 of 40 CFR Part 98, Subpart A.

5.6 Turbine Startup and Shutdown

The emissions associated with SUSD activities from the turbines for simple cycle operations in Scenario 1 and for Scenario 2 Phase 1 are calculated based on the projected fuel flow for fast startup and shutdown, the fuel heat capacity (HHV), duration of 30 minutes per activity, and the estimated annual frequency. For Scenario 2 Phase 2, the fuel flow during SUSD will be much lower than that of normal operation; therefore, SUSD GHG emissions are accounted for and included as part of the total GHG emissions already proposed for the combined cycle normal operation.

SECTION 6
BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

Since the GHG emissions associated with the proposed project will trigger a PSD review, each new GHG emissions unit is subject to BACT review. The emission units subject to BACT review in the proposed project are combustion turbines, HRSGs, fugitive equipment leaks, insulated equipment, the auxiliary boiler, and the firewater pump. Since the project proposes to operate the combustion turbines in simple and combined cycle modes, BACT analysis for combustion turbines is performed separately for simple and combined cycle modes.

6.1 Federal PSD BACT Analysis Methodology

BACT is defined in 40 CFR Part §52.21(b) (12) as "...an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from a source which on a case-by-case basis is determined to be achievable taking into account energy, environmental and economic impacts and other costs". In the USEPA guidance documents titled the *1990 Draft New Source Review Workshop Manual*, USEPA recommends the use of the Agency's five-step "top-down" BACT process to determine BACT for PSD permit applications in general. In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT. The five basic steps of a top-down BACT analysis are listed below:

Step 1: Identify potential control technologies;

Step 2: Eliminate technically infeasible options;

Step 3: Rank remaining control technologies;

Step 4: Evaluate the most effective controls and document results; and

Step 5: Select the BACT.

The first step is to identify potentially "available" control options for each emission unit subject to BACT review, for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emission unit in question. For this analysis, the following sources are typically consulted when identifying potential technologies:

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC) Database;
- Proposed NSPS Subpart TTTT;

- Other recently submitted GHG permit applications that are associated with similar process types; and
- Engineering experience with similar control applications.

After identifying potential technologies, the second step is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must be both available and applicable. A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available".

The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern.

The fourth step entails an evaluation of energy, environmental, and economic impacts for determining a final level of control. The evaluation begins with the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts.

The fifth and final step is to select as BACT the most effective of the remaining technologies under consideration for each pollutant of concern.

6.2 Combined Cycle Combustion Turbine BACT Analysis

6.2.1 Step 1 – Identify All Available Control Technologies

The following are potential technological alternatives to minimize GHG emissions from natural gas combustion in turbines and duct burners:

- Use of low carbon fuels.
- Energy efficient processes, practices, and designs that apply to:
  - Combustion turbine;
  - Heat recovery steam generator and duct burners;
  - Steam turbine; and
  - Other plant-wide equipment.
- Add-on Controls:
  - Carbon capture and sequestration (CCS), including CO_2 capture, compression, transport, and storage.

6.2.1.1 Low Carbon Fuels

CO_2 is a product of combustion of fuel containing carbon, which is inherently present in any power generation technology using fossil fuel. It is not possible to reduce the amount of CO_2 generated from fuel combustion, as CO_2 is the essential product of the chemical reaction between the fuel and the oxygen in which it burns, not a byproduct caused by imperfect combustion. As such, using certain fuel types can effectively minimize CO_2 generation in which combustion takes place. Table 6-1 in this section presents the amount of CO_2 formed when combusting fossil fuels.

Table 6-1 CO_2 Emission Factors[1]

Fuel Type	Default CO_2 Emission Factor
Coal and coke	kg CO_2/mmBtu
Anthracite	103.69
Bituminous	93.28
Subbituminous	97.17
Lignite	97.72
Coal Coke	113.67
Mixed (Commercial sector)	94.27
Mixed (Industrial coking)	93.90
Mixed (Industrial sector)	94.67
Mixed (Electric Power sector)	95.52
Natural gas	kg CO_2/mmBtu
(Weighted U.S. Average)	53.06
Petroleum products	kg CO_2/mmBtu
Distillate Fuel Oil No. 1	73.25
Distillate Fuel Oil No. 2	73.96
Distillate Fuel Oil No. 4	75.04
Residual Fuel Oil No. 5	72.93
Residual Fuel Oil No. 6	75.10
Used Oil	74.00
Kerosene	75.20
Liquefied petroleum gases (LPG)1	61.71
Propane	62.87
Propylene	67.77
Ethane	59.60
Ethanol	68.44
Ethylene	65.96
Isobutane	64.94

Fuel Type	Default CO_2 Emission Factor
Isobutylene	68.86
Butane	64.77
Butylene	68.72
Naphtha (<401 deg F)	68.02
Natural Gasoline	66.88
Other Oil (>401 deg F)	76.22
Pentanes Plus	70.02
Petrochemical Feedstocks	71.02
Petroleum Coke	102.41
Special Naphtha	72.34
Unfinished Oils	74.54
Heavy Gas Oils	74.92
Lubricants	74.27
Motor Gasoline	70.22
Aviation Gasoline	69.25
Kerosene-Type Jet Fuel	72.22
Asphalt and Road Oil	75.36
Crude Oil	74.54
Other fuels—solid	kg CO_2/mmBtu
Municipal Solid Waste	90.7
Tires	85.97
Plastics	75.00
Petroleum Coke	102.41
Other fuels—gaseous	kg CO_2/mmBtu
Blast Furnace Gas	274.32
Coke Oven Gas	46.85
Propane Gas	61.46
Fuel Gas	59.00
Biomass fuels—solid	kg CO_2/mmBtu
Wood and Wood Residuals (dry basis)	93.80
Agricultural Byproducts	118.17
Peat	111.84

Fuel Type	Default CO_2 Emission Factor
Solid Byproducts	105.51
Biomass fuels—gaseous	kg CO_2/mmBtu
Landfill Gas	52.07

[1] *Obtained from 40 CFR Part 98, Subpart C, Table C-1, [78 FR 71950, Nov. 29, 2013]*

As shown in the table above, natural gas produces nearly the lowest level of CO_2 emissions from the combustion process compared to other fuels on the list. Thus, the use of natural gas in the turbines and duct burners will generate nearly the lowest level of CO_2 from combustion compared to the use of other alternative fuels. Only coke oven gas and landfill gas have lower CO_2 emission factors than natural gas. However, these gases will be not be available for the Neches Station; therefore, it is technically infeasible to consider landfill or coke oven gas for the project.

6.2.1.2 Energy Efficient Processes/Practices/Designs

A search of the EPA's RACT/BACT/LAER Clearinghouse for natural gas-fired combustion turbine generators was conducted to find past determinations on BACT for GHG emissions. Additionally, although not listed in the RACT/BACT/LAER Clearinghouse, a GHG BACT analysis was found on the Russell City Energy Center, a 612 MW natural gas-fired combined cycle power plant to be located in Hayward, California. The Russell City Energy Center project included two Siemens-Westinghouse 501FD3 combustion turbines. That analysis determined that BACT for GHG emissions was to maintain the high energy efficiency that is inherent with natural gas-fired combined cycle power plants. A summary of available, lower greenhouse gas emitting processes, practices, and designs for combustion turbine power generators, is presented below.

6.2.1.2.1 Combustion Turbine Energy Efficient Processes, Practices, and Designs

Combustion Turbine Design

As stated above, CO_2 is a product of combustion of fuel containing carbon, which is inherently present in any power generation technology using fossil fuel. The only effective means to reduce the amount of CO_2 generated by a fuel-burning power plant is to generate as much electric power as possible from the combustion, thereby reducing the amount of fuel needed to meet the plant's required power output. This result is obtained by using the most efficient generating technologies available, so that as much of the energy content of the fuel as possible goes into generating power.

For fossil fuel technologies, efficiency ranges from approximately 30-50% HHV. A typical coal-fired Rankine cycle power plant has a base load efficiency of approximately 30% (HHV), while a modern F-Class natural gas fired combined cycle unit operating under optimal conditions has a baseload efficiency of approximately 50% (HHV).

Combined cycle units operate based on a combination of two thermodynamic cycles: the Brayton and the Rankine cycles. A combustion turbine operates on the Brayton cycle and the HRSG and steam turbine operate on the Rankine cycle. The combination of the two thermodynamic cycles allows for the high efficiency associated with combined cycle plants.

The combined-cycle natural gas turbine technology proposed for the Neches Station is generic F-Class turbine technology which is the current state-of-the-art electrical generating equipment for a facility of this type.

In addition to the high-efficiency primary components of the turbine, there are a number of other design features employed within the combustion turbine that can improve the overall efficiency of the machine. These additional features include those summarized below.

Periodic Burner Tuning

Modern F-Class combustion turbines have regularly scheduled maintenance programs. These maintenance programs are important for the reliable operation of the unit, as well as to maintain optimal efficiency. As the combustion turbine is operated, the unit experiences degradation and loss in performance. The combustion turbine maintenance program helps restore the recoverable lost performance. The maintenance program schedule is determined by the number of hours of operation and/or turbine starts. There are three basic maintenance levels, commonly referred to as combustion inspections, hot gas path inspections, and major overhauls. Combustion inspections are the most frequent of the maintenance cycles. As part of this maintenance activity, the combustors are tuned to restore highly efficient low-emission operation.

Reduction in Heat Loss

Modern F-Class combustion turbines have high operating temperatures. The high operating temperatures are a result of the heat of compression in the compressor along with the fuel combustion in the burners. To minimize heat loss from the combustion turbine and protect the personnel and equipment around the machine, insulation blankets are applied to the combustion turbine casing. These blankets minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine.

Instrumentation and Controls

Modern F-Class combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital type and is supplied with the combustion turbine. The distributed control system (DCS) controls all aspects of the turbine's operation, including the fuel feed and burner operations. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency low-emission performance for full-load and part-load conditions.

6.2.1.2.2 Heat Recovery Steam Generator Energy Efficient Processes, Practices, and Designs

The HRSG takes waste heat from the combustion turbine exhaust and uses the waste heat to convert boiler feed water to steam. Duct burning involves burning additional natural gas in the ducts to the heat recovery boiler, which increases the temperature of the exhaust coming from the combustion turbines and thereby creates additional steam for the steam turbine. For cogeneration units, such as the proposed Scenario 2 design, duct burner firing serves two purposes: (1) additional power generation capacity during periods of high electrical demand, and (2) additional steam generation capacity during periods of high steam demand from the host facility.

The modern F-Class combustion turbine-based combined cycle HRSG is generally a horizontal natural circulation drum-type heat exchanger designed with three pressure levels of steam generation, reheat, split superheater sections with interstage attemperation, post-combustion emissions control equipment, and condensate recirculation. The HRSG is designed to maximize the conversion of the combustion turbine exhaust gas waste heat to steam for all plant ambient and load conditions. Maximizing steam generation will increase the steam turbine's power generation, which maximizes plant efficiency.

Heat Exchanger Design Considerations

HSRGs are heat exchangers designed to capture as much thermal energy as possible from the combustion turbine exhaust gases. This is performed at multiple pressure levels. For a drum-type configuration, each pressure level incorporates an economizer section(s), evaporator section, and superheater section(s). These heat transfer sections are made up of many thin-walled tubes to provide surface area to maximize the transfer of heat to the working fluid. Most of the tubes also include extended surfaces (e.g., fins). The extended surface optimizes the heat transfer, while minimizing the overall size of the HRSG. Additionally, flow guides are used to distribute the flow evenly through the HRSG to allow for efficient use of the heat transfer surfaces and post-combustion emissions control components. Low-temperature economizer sections maximize the amount of energy used in the cycle by removing heat until the gas is cooled to its limits with respect to tube corrosion purposes. In addition, stack dampers are used for cycling operation to conserve the thermal energy within the HRSG when the unit is offline.

Insulation

HRSGs take waste heat from the combustion turbine exhaust gas and uses that waste heat to convert boiler feed water to steam. As such, the temperatures inside the HRSG are nearly equivalent to the exhaust gas temperatures of the turbine. For F-Class combustion turbines, these temperatures can approach 1,200°F. HRSGs are designed to maximize the conversion of the waste heat to steam. One aspect of the HRSG design in maximizing this waste heat conversion is the use of insulation. Insulation minimizes heat loss to the surroundings, thereby improving the overall efficiency of the HRSG. Insulation is applied to the HRSG panels that make up the shell of the unit, to the high-temperature steam and water lines, and typically to the bottom portion of the stack.

Minimizing Fouling of Heat Exchange Surfaces

HRSGs are made up of a number of tubes within the shell of the unit that are used to generate steam from the combustion turbine exhaust gas waste heat. To maximize this heat transfer, the tubes and their extended surfaces need to be as clean as possible. Fouling of the tube surfaces impedes the transfer of heat. Fouling occurs from the constituents within the exhaust gas stream. To minimize fouling, filtration of the inlet air to the combustion turbine is performed. Additionally, cleaning of the tubes is performed during periodic outages. By reducing the fouling, the efficiency of the unit is maintained.

Minimizing Vented Steam and Repair of Steam Leaks

As with all steam-generated power facilities, minimization of steam vents and repair of steam leaks is important in maintaining the plant's efficiency. A combined cycle facility has just a few locations where steam is vented from the system, including at the deaerator vents, blowdown tank vents, and vacuum pumps/steam jet air ejectors. These vents are necessary to improve the overall heat transfer within the HRSG and condenser by removing solids and air that potentially blankets the heat transfer surfaces lowering the equipment's performance. Steam leaks are repaired as soon as possible to maintain facility performance and maintain a high efficiency of the facilities. Minimization of vented steam and repair of steam leaks will be performed for this proposed station.

6.2.1.2.3 Plant-wide Energy Efficient Processes, Practices, and Designs

There are a number of other components within the combined cycle plant that help improve overall efficiency, including:

- **Fuel gas preheating** – The overall efficiency of the combustion turbine is increased with increased fuel inlet temperatures. For the F-class combustion turbine based combined cycle, the fuel gas is generally heated with high temperature water from the HRSG. This improves the efficiency of the combustion turbine.
- **Drain operation** – Drains are required to allow for draining the equipment for maintenance (i.e., maintenance drains), and also to allow condensate to be removed from the steam piping and drains for operation (i.e., operation drains). Operation drains are generally controlled to minimize the loss of energy from the cycle. This is accomplished by closing the drains as soon as the appropriate steam conditions are achieved.
- **Multiple combustion turbine/HRSG trains** – Multiple combustion turbine/HRSG trains help with part-load operation. The multiple trains allow the unit to achieve higher overall plant part-load efficiency by shutting down trains operating at less efficient part-load conditions and ramping up the remaining train(s) to high-efficiency full-load operation.
- **Boiler feed pump fluid drives** – The boiler feed pumps are used as the means to impart high pressure on the working fluid. The pumps require considerable power. To minimize the power consumption at part-loads, the use of fluid drives or variable-

frequency drives can be employed. For this project, fluid drives are being used to minimize power consumption and part-load, improving the facility's overall efficiency.

6.2.1.3 Carbon Capture and Storage

In addition to power generation process technology options discussed above, it is appropriate to consider add-on technologies as possible ways to capture GHG emissions that are emitted from natural gas combustion in the proposed project's CTG/HRSG unit and to prevent them from entering the atmosphere. These emerging carbon capture and storage (CCS) technologies generally consist of processes that separate CO_2 from combustion process flue gas, and then inject it into geological formations such as oil and gas reservoirs, unmineable coal seams, and underground saline formations. Of the emerging CO_2 capture technologies that have been identified, only amine absorption is currently commercially used for state-of-the-art CO_2 separation processes. Amine absorption has been applied to processes in the petroleum refining and natural gas processing industries and for exhausts from gas-fired industrial boilers. Other potential absorption and membrane technologies are currently considered developmental. The U.S. Department of Energy's National Energy Technology Laboratory (DOE-NETL) provides the following brief description of state-of-the-art post-combustion CO_2 capture technology and related implementation challenges[1]:

> "...In the future, emerging R&D will provide numerous cost-effective technologies for capturing CO_2 from power plants. At present, however, state-of-the-art technologies for existing power plants are essentially limited to amine absorbents. Such amines are used extensively in the petroleum refining and natural gas processing industries... Amine solvents are effective at absorbing CO_2 from power plant exhaust streams—about 90 percent removal—but the highly energy-intensive process of regenerating the solvents decreases plant electricity output..."

The DOE-NETL adds:

> "...Separating CO_2 from the flue gas streams is challenging for several reasons:
>
> - CO_2 is present at dilute concentrations (13-15 volume percent in coal-fired systems and 3-4 volume percent in gas-fired turbines) and at low pressure (15-25 pounds per square inch absolute [psia]), which dictates that a high volume of gas be treated.
> - Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes.
> - Compressing captured or separated CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall power plant system..."

If CO_2 capture can be achieved at a power plant, it would need to be routed to a geological formation capable of long-term storage. The long-term storage potential for a formation is a

[1] http://www.netl.doe.gov/technologies/carbon seq/FAQs/tech-status.html, 2012

function of the volumetric capacity of a geological formation and CO_2 trapping mechanisms within the formation, including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock. The DOE-NETL describes the geological formations that could potentially serve as CO_2 storage sites as follows[2]:

> "Geological carbon dioxide (CO_2) storage involves the injection of supercritical CO_2 into deep geological formations (injection zones) overlain by competent sealing formations and geological traps that will prevent the CO_2 from escaping. Current research and field studies are focused on developing better understanding of 11 major types of geological storage reservoir classes, each having their own unique opportunities and challenges. Understanding these different storage classes provides insight into how the systems influence fluids flow within these systems today, and how CO_2 in geological storage would be anticipated to flow in the future. The different storage formation classes include: deltaic, coal/shale, fluvial, alluvial, strandplain, turbidite, eolian, lacustrine, clastic shelf, carbonate shallow shelf, and reef. Basaltic interflow zones are also being considered as potential reservoirs. These storage reservoirs contain fluids that may include natural gas, oil, or saline water; any of which may impact CO_2 storage differently..."

6.2.1.3.1 CO_2 Capture and Compression

Though amine absorption technology for CO_2 capture has been applied to processes in the petroleum refining and natural gas processing industries and to exhausts from gas-fired industrial boilers, it is not yet commercially available for power plant gas turbine exhausts, which have considerably larger flow volumes and considerably lower CO_2 concentrations. The Obama Administration's Interagency Task Force on Carbon Capture and Storage confirms this in its recently completed report on the current status of development of CCS systems[3]:

> "Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."

6.2.1.3.2 CO_2 Transport

Even if it is assumed that CO_2 capture and compression could feasibly be achieved for the proposed project, the high-volume CO_2 stream generated would need to be transported to a facility capable of storing it. The potential length of such a CO_2 transport pipeline is uncertain due to the uncertainty of identifying a site(s) that is suitable for

[2] http://www.netl.doe.gov/technologies/carbon seq/FAQs/tech-status.html, 2012
[3] Report of the Interagency Task Force on Carbon Capture and Storage, http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf, 2010

large-scale, long-term CO_2 storage. The hypothetical minimum length required for any such pipeline(s) will be the lesser of the following:

- The distance to the closest site with the recognized potential for some geological storage of CO_2 (the potential sites are shown in Figure 6-1 and Table 6-2 below), or
- The straight-line distance of 157 miles to a CO_2 pipeline that Denbury Green Pipeline-Texas has constructed for the purpose of providing CO_2 to support various EOR operations in Southeast Texas. It should be noted that the actual proposed distance for the connecting pipeline is 236 miles, which includes a contingency factor of 1.5. This contingency factor takes into account the need for obtaining contracts for offsite land acquisition for pipeline right-of-way. Also, it is not reasonable to assume that the right-of-way to construct a pipeline from the Neches Station will be a direct straight line to the Denbury Green Pipeline tie in point.[4]

Table 6-2 Potential CO_2 Storage/EOR Sites[5]

Source	Type	Distance	Capacity	Status
FutureGen – Jewett Plant	Capture and Storage	63 miles	N/A	Closed
ZENG Worsham-Steed Plant	Capture and Storage	148 miles	790 tons/day	Potential – Planned
Frio Brine Pilot Plant	Storage	151 miles	1,600 total tons	Completed – Insufficient Capacity
Denbury Green Pipeline	Transport (Storage)	157 miles	N/A	Active - Existing

As seen in Table 6-2, no sites with a distance of less than 157 miles from the Neches Station are suitable candidates for CO_2 storage/EOR. The three sites closer than the Denbury Green Pipeline are unsuitable for the following reasons:

- FutureGen – Jewett Plant: site has been closed.
- ZENG Worsham-Steed Plant: site is still in the planning phase and is not yet completed.
- Frio Brine Pilot Plant: site does not have the CO_2 storage capacity needed to store all of the CO_2 captured from the Neches Station.

In comparison, the closest site that is currently being field-tested to demonstrate its capacity for large-scale geological storage of CO_2 is the Southeast Regional Carbon Sequestration Partnership's (SECARB) Cranfield test site, which is located in Adams and Franklin Counties, Mississippi and is 252 miles away (see Figure 6-1 for the test site location). Therefore, to access this potentially large-scale storage capacity site, assuming that it is eventually demonstrated to indefinitely store a substantial portion of the large volume of CO_2 generated by the proposed project, a very long and sizable pipeline would need to be constructed to transport the large

[4] U.S. Environmental Protection Agency, response to public comments on Celanese Clear Lake Plant, pg. 19, http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/celanese-resp2public-comment.pdf
[5] Information obtained from the National Carbon Sequestration Database and Geographic Information System (NATCARB), http://www.natcarbviewer.com

volume of high-pressure CO_2 from the plant to the storage facility, thereby rendering implementation of a CO_2 transport system infeasible.

6.2.1.3.3 CO_2 Storage

Assuming CO_2 capture and compression could feasibly be achieved for the proposed project and that the CO_2 could be transported economically, the feasibility of CCS technology would still depend on the availability of a suitable sequestration site. The suitability of potential storage sites is a function of volumetric capacity of their geologic formations, CO_2 trapping mechanisms within formations (including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock), and potential environmental impacts resulting from injection of CO_2 into the formations. Potential environmental impacts resulting from CO_2 injection that still require assessment before CCS technology can be considered feasible include:

- Uncertainty concerning the significance of dissolution of CO_2 into brine,
- Risks of brine displacement resulting from large-scale CO_2 injection, including a pressure leakage risk for brine into underground drinking water sources and/or surface water,
- Risks to fresh water as a result of leakage of CO_2, including the possibility for damage to the biosphere, underground drinking water sources, and/or surface water, and
- Potential effects on wildlife.

Potentially suitable storage sites, including EOR sites and saline formations, exist in Texas, Louisiana, and Mississippi. As shown in Figure 6-1, sites with such recognized potential for some geological storage of CO_2 are located within 15 miles of the proposed project, but such nearby sites have not yet been technically demonstrated with respect to all of the suitability factors described above. In comparison, the closest site that is currently being field-tested to demonstrate its capacity for geological storage of the volume of CO_2 that would be generated by the proposed power unit, i.e., SECARB's Cranfield test site, is located in Mississippi over 260 miles away. It should be noted that, based on the suitability factors described above, currently the suitability of the Cranfield site or any other test site to store a substantial portion of the large volume of CO_2 generated by the proposed project has yet to be fully demonstrated.

6.2.2 Step 2 – Eliminate Technically Infeasible Options

This section addresses the potential feasibility of implementing CCS technology as BACT for GHG emissions from the proposed project's gas turbine/HRSG train.

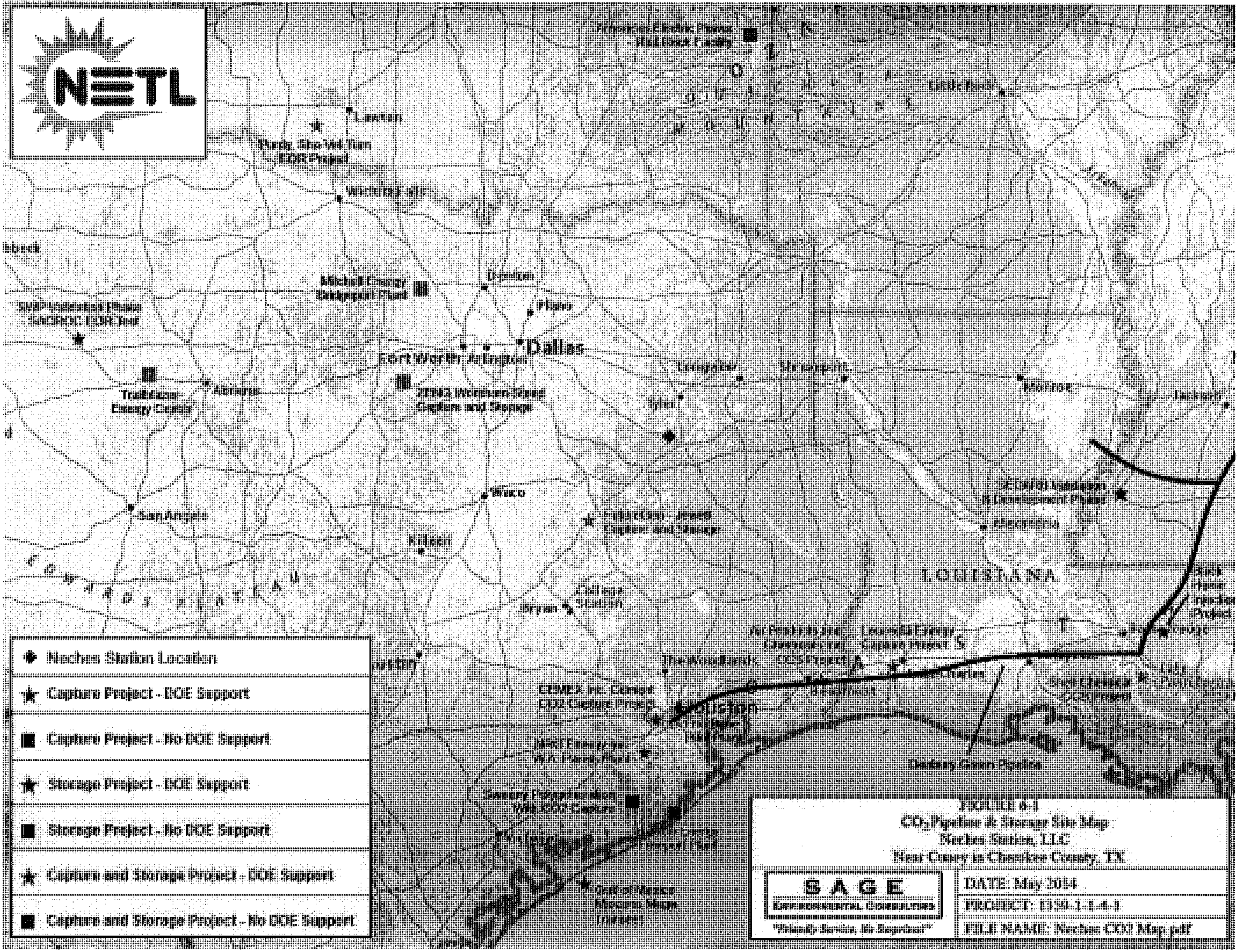

FIGURE 6-1
CO_2 Pipeline & Storage Site Map
Neches Station, LLC
Near Cuney in Cherokee County, TX

DATE: May 2014
PROJECT: 1159-1-1-4-1
FILE NAME: Neches CO2 Map.pdf

Based on the reasons provided in Step 1, Apex believes that CCS technology should be eliminated from further consideration as a potential feasible control technology for purposes of this BACT analysis. However, although technically challenging, it may not be technically infeasible; therefore CCS technology will be considered technically feasible for the purposes of top-down BACT analysis.

6.2.3 Step 3 – Rank Remaining Control Technologies

CCS control technology, energy efficient processes, practices, and designs, and use of low carbon fuels are being ranked by most effective control technology in Step 3 of the top-down BACT analysis as follows:

- CCS
- Energy efficient processes, practices, and designs
- Use of low carbon fuels

CCS technology may be associated with a potential 90% capture efficiency, making it a more effective control technology than the energy efficient processes, practices, and designs. The use of low carbon fuels, the energy efficient processes, practices, and designs have not been quantified, as they are all being proposed for this project.

6.2.4 Step 4 – Evaluate Most Effective Controls and Document Results

As the low carbon fuel discussed in Section 6.2.1.1, and all of the energy efficient processes, practices, and designs discussed in Section 6.2.1.2 of this application are being proposed for this project, an examination of the energy, environmental, and economic impacts of the efficiency designs is not necessary for this application. However, an economic evaluation of the costs associated with CCS technology is provided below in Tables 6-3, 6-4, and 6-5.

Scenario 2

Table 6-3: CO_2 Pipeline/Injection Well/Plant Assumptions	
Pipeline Length	235.8 miles
Pipeline Diameter	14 inches
Natural Gas for Econamine Process[2]	1,836 MMBtu/hr
Gross Plant Output	794,000 kW

Table 6-4: Carbon Capturing System Cost Estimate			
Cost Type	Units	Cost	
Pipeline Costs[1]			
Pipeline Materials	$ Diameter (inches), Length (miles)	$70,350 + $2.01 x L x (330.5 x D^2+687.7 x D + 26,920)	$48,087,888
Pipeline Labor	$ Diameter (inches), Length (miles)	$371,850 + $2.01 x L x (343.2 x D^2 + 2,074 x D + 170,013)	$126,594,544
Pipeline Miscellaneous	$ Diameter (inches), Length (miles)	$147,250 + $1.55 x L x (8,417 x D + 7,234)	$45,859,815
Pipeline Right of Way	$ Diameter (inches), Length (miles)	$52,200 + $1.28 x L x (577 x D + 29,788)	$11,481,068
Other Capital[2]			
CO_2 Amine Removal System	$ per kW	$456 x kW	$362,064,000
CO_2 Compression and Drying	$ per kW	$52 x kW	$41,288,000
O&M - Pipeline[3]			
Fixed O&M	$/mile/year	$8,454	$1,993,453
O&M - Capture			
Fixed O&M	% of installed capital	3.0%	$12,100,560
CO_2 CCS Natural Gas Consumption	$ per MMBtu	$3.00	$48,250,080
Amine Replacement	$ per year	Engineering Estimate	$3,000,000
		Total Project Capital Cost (with CCS)	**$1,185,375,314**
		Total Project Capital Cost (without CCS)	**$550,000,000**

1. National Energy Technology Laboratory, "Carbon Dioxide Transport and Storage Costs in NETL Studies," DOE/NETL - 2013/1614, March 2013.

2. National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants," NETL - Rev. 2a, November 2013.

3. National Energy Technology Laboratory. "Estimating Carbon Dioxide Transport and Storage Costs," DOE/NETL-400/2010/1447, March 2010

Scenario 2

Table 6-5: Amortized CCS Cost	
CCS Total Capital Investment (TCI)	\$635,375,314
Capital Recovery Factor (CRF) = $i(1+i)^n/((1+i)^n-1)$	0.1095
i = interest rate[2]	0.09
n = equipment life, years	20
Amortized Installation Costs = CRF x TCI	\$69,603,126.01
Annual O&M Costs	\$65,344,093
Total CCS Annualized Cost	**\$134,947,219.21**
Tons CO_2 per Year Removed	**2,878,020**
CO_2 Sold for EOR (\$/ton)[1]	**\$20.00**
Average Annual Cost per Ton CO_2 Removed	**\$26.89**
(Assuming 90% Capture and Transfer)	
CCS Capital Cost as Percentage of Total Project Capital Cost (without CCS)	**115.52%**

1. From Sierra Club comments on Freeport LNG GHG application; \$9 to \$34 per ton CO2. The midpoint of this range was used.

2. Interest rate is based on a private capital investment.

As demonstrated by the cost analysis table above, the use of CCS as an add-on control technology would make the power plant project economically unviable. This is shown by the CCS estimated capital cost for Scenario 2 ($635,400,000) being higher than the estimated capital cost of the entire project without CCS ($550,000,000). Therefore, CCS technology is considered economically infeasible and will not be considered any further in the top-down BACT analysis.

6.2.5 Step 5 – Select BACT

Apex proposes as BACT for this project, the following fuel type, energy efficiency process, practices, and designs for the proposed combined cycle combustion turbine:

- Use of low carbon fuel
- Use of Combined Cycle Power Generation Technology
- Combustion turbine energy efficient processes, practices, and designs
  - Efficient turbine design
  - Turbine inlet air cooling
  - Periodic turbine burner tuning
  - Reduction in heat loss
  - Instrumentation and controls
- HRSG energy efficient processes, practices, and designs
  - Efficient heat exchanger design
  - Insulation of HSRG
  - Minimizing fouling of heat exchanger surfaces
  - Minimizing vented steam and repair of steam leaks
- Plant-wide energy efficient processes, practices, and designs
  - Fuel gas preheating
  - Drain operation
  - Multiple combustion turbine/HRSG trains
  - Boiler feed pump fluid drive design

To determine the appropriate heat-input efficiency limit, Apex started with the turbine's design base load gross power output (in MW) and gross heat rate (Btu/kWh) for combined cycle operation and then calculated the equivalent lb CO_2/MWh BACT efficiency limits. Additionally, margins were added to account for equipment degradation and other efficiency losses over time. Apex proposes the following output based BACT limit for the electric generating turbines in combined cycle mode (limit based on a twelve-month rolling average, not including turbine operation during startup and shutdown):

- Combined Cycle Operation = 973.96 lb CO_2/MWh (0.49 tons CO_2/MWh)

Detailed calculations of the BACT output limits are provided in Table A-2-6 in Appendix A.

Table 6-6 compares other similar PSD permits and associated BACT limits to Apex's proposed BACT limits. It demonstrates the Apex's proposed combined cycle BACT is better or equivalent to recently permitted facilities.

Table 6-6 Combined Cycle BACT Limit Comparison

Facility	State	BACT Gross Output Limit (tons CO_2/MWh)	Source
Calpine Corporation - Deer Park Energy Center	TX	0.51	EPA Region VI Air Permit Statement of Basis (SOB) & applications
Calpine Corporation - Channel Energy Center	TX	0.51	EPA Region VI Air Permit SOB & applications
La Paloma Energy Center	TX	0.44 - 0.47	EPA Region VI Air Permit SOB & applications

6.3 Simple Cycle Combustion Turbine BACT Analysis

The electric generating facilities at the Neches Station will be constructed as one of the proposed scenarios described previously. Although a combined cycle mode is a more efficient means of electric generation, the electricity needs in the region may warrant the construction and/or operation of peaking units. Apex is requesting to be able to operate the proposed turbines in simple cycle mode for Scenario 1 and for both phases of Scenario 2; Phase 1 (prior to construction of the HRSGs and steam turbine), and Phase 2 (when electricity demand profiles call for peaking and load following power). Because these units may not operate continuously, the turbines would still be able to meet peak power demands for small periods of time.

6.3.1 Step 1 – Identify All Available Control Technologies

The following control technologies were identified and were evaluated for simple cycle operation of the electric generating facilities:

- Combustion Turbine Design and Operation – The combustion turbine design, periodic tuning, reduction in heat loss, and instrumentation and controls as potential control technologies are described in Section 6.2.1.1.1 above. These design and practices are not affected by the mode of operation (simple or combined);

- Evaporative Cooling – Evaporative cooling is associated with the cooling of the gas turbine inlet air in order to increase combustion air mass flow. The air flows through a wetted medium and is cooled as some of the water evaporates off of the medium and into the combustion inlet air, which reduces the temperature of the inlet combustion air. Cooling the combustion air increases density, which results in a higher mass flow rate and pressure ratio, which increases turbine output and efficiency;

- Fuel Selection – Natural gas has lower carbon intensity than any other fuels available for use in electric generating turbines;
- Limit annual operation time to 2,500 hours/yr per turbine; and
- CCS

6.3.2 Step 2 – Eliminate Technically Infeasible Options

All options identified in Step 1 are considered technically feasible and therefore need to be considered in Step 3 of the top-down BACT analysis.

6.3.3 Step 3 – Rank Remaining Control Technologies

CCS control technology, energy efficient processes, practices, and designs, and use of low carbon fuels are being ranked by most efficient control method in Step 3 of the top-down BACT analysis as follows:

- CCS
- Combustion Turbine Design and Operation
- Fuel Selection
- Evaporative Cooling
- Limit annual operation time to 2,500 hours/yr per turbine

CCS technology may be associated with a potential 90% capture efficiency, making it a more effective control technology than the low carbon fuels, energy efficient processes, practices, and designs, and low annual capacity factor. Aside from CCS technology, the control technologies identified in Step 1 are all top-ranked control technologies for turbines in simple cycle operation. The use of one technology does not preclude the use of any other control technology and the combination of the control technologies and best practices will result in a higher efficiency than any one alone. Therefore, ranking of the control technologies is not necessary.

6.3.4 Step 4 – Evaluate Most Effective Controls and Document Results

Consistent with Section 6.2.4, an economic evaluation of the costs associated with CCS technology is provided below in Tables 6-7, 6-8, and 6-9.

Scenario 1

Table 6-7: CO_2 Pipeline/Injection Well/Plant Assumptions	
Pipeline Length	235.8 miles
Pipeline Diameter	14 inches
Natural Gas for Econamine Process[2]	2,150 MMBtu/hr
Gross Plant Output	930,000 kW

Table 6-8: Carbon Capturing System Cost Estimate

Cost Type	Units	Cost	
Pipeline Costs[1]			
Pipeline Materials	$ Diameter (inches), Length (miles)	$70,350 + $2.01 x L x (330.5 x D^2+687.7 x D + 26,920)	$48,087,888
Pipeline Labor	$ Diameter (inches), Length (miles)	$371,850 + $2.01 x L x (343.2 x D^2 + 2,074 x D + 170,013)	$126,594,544
Pipeline Miscellaneous	$ Diameter (inches), Length (miles)	$147,250 + $1.55 x L x (8,417 x D + 7,234)	$45,859,815
Pipeline Right of Way	$ Diameter (inches), Length (miles)	$52,200 + $1.28 x L x (577 x D + 29,788)	$11,481,068
Other Capital[2]			
CO_2 Amine Removal System	$ per kW	$456 x kW	$424,080,000
CO_2 Compression and Drying	$ per kW	$52 x kW	$48,360,000
O&M - Pipeline[3]			
Fixed O&M	$/mile/year	$8,454	$1,993,453
O&M - Capture			
Fixed O&M	% of installed capital	3.0%	$14,173,200
CO_2 CCS Natural Gas Consumption	$ per MMBtu	$3.00	$56,502,000
Amine Replacement	$ per year	Engineering Estimate	$3,000,000
		Total Project Capital Cost (with CCS)	**$1,204,463,314**
		Total Project Capital Cost (without CCS)	**$500,000,000**

1. National Energy Technology Laboratory, "Carbon Dioxide Transport and Storage Costs in NETL Studies," DOE/NETL - 2013/1614, March 2013.

2. National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants," NETL - Rev. 2a, November 2013.

3. National Energy Technology Laboratory. "Estimating Carbon Dioxide Transport and Storage Costs," DOE/NETL-400/2010/1447, March 2010

Scenario 1

Table 6-9: Amortized CCS Cost	
CCS Total Capital Investment (TCI)	$704,463,314
Capital Recovery Factor (CRF) = $i(1+i)^n/((1+i)^n-1)$	0.1095
i = interest rate[2]	0.09
n = equipment life, years	20
Amortized Installation Costs = CRF x TCI	$77,171,472.87
Annual O&M Costs	$75,668,653
Total CCS Annualized Cost	**$152,840,126.07**
Tons CO_2 per Year Removed	**1,390,031**
CO_2 Sold for EOR ($/ton)[1]	**$20.00**
Average Annual Cost per Ton CO_2 Removed	**$89.95**
(Assuming 90% Capture and Transfer)	
CCS Capital Cost as Percentage of Total Project Capital Cost (without CCS)	**140.89%**

1. From Sierra Club comments on Freeport LNG GHG application; $9 to $34 per ton CO2. The midpoint of this range was used.

2. Interest rate is based on a private capital investment.

As demonstrated by the cost analysis table above, the use of CCS as an add-on control technology would make the power plant project economically unviable. This is shown by the CCS estimated capital cost for Scenario 1 ($704,500,000) being higher than the estimated capital cost of the entire project without CCS ($500,000,000). Therefore, CCS technology is considered economically infeasible and will not be considered any further in the top-down BACT analysis.

Other than CCS, all aforementioned control technologies are considered economically reasonable. Additionally, the potential control technologies will not be associated with any adverse environmental impacts.

6.3.5 Step 5 – Select BACT

Apex proposes as BACT for this project, the following fuel type, energy efficiency process, practices, and designs for the proposed simple cycle combustion turbine:

- Combustion Turbine Energy Efficient Processes, Practices, and Designs
  - Efficient turbine design
  - Turbine inlet air cooling
  - Periodic turbine burner tuning
  - Reduction in heat loss
  - Instrumentation and controls
- Fuel selection
- Limit annual operations – Apex also proposes limiting annual operation of the turbines in simple cycle mode to 2,500 hours/yr per turbine as a means to minimize GHG emissions.

To determine the appropriate heat-input efficiency limit, Apex started with the turbine's design base load gross power output (in MW) and gross heat rate (Btu/kWh) for simple cycle operation and then calculated the equivalent lb CO_2/MWh BACT efficiency limits. Additionally, margins were added to account for equipment degradation and other efficiency losses over time. Apex proposes the following output based BACT limit for the electric generating turbines in simple cycle operation (limit based on a twelve-month rolling average, not including turbine operation during startup and shutdown)

- Simple Cycle Operation = 1,378.27 lb CO_2/MWh (0.69 tons CO_2/MWh)

Detailed calculations of the BACT output limits are provided in Tables A-1-5 and A-2-6 in Appendix A.

Table 6-10 compares sites with similar PSD permits and associated BACT limits to Apex's proposed BACT limits used in their BACT evaluation. The table demonstrates that Apex's proposed simple cycle BACT is better than or equivalent to recent permitted facilities.

Table 6-10 Simple Cycle BACT Limit Comparison

Facility	State	BACT Output Limit (tons CO_2/MWh)	Source
Tenaska – Roan's Prairie Generating Station	TX	0.667	EPA Region VI Air Permit SOB and application
Golden Eagle Electric Cooperative - Antelope Station	TX	0.757	EPA Region VI Air Permit SOB and application *(Permit Incomplete)
Austin Energy - Sand Hill Energy Center	TX	0.810	EPA Region VI Air Permit SOB and application *(Permit Incomplete)

6.4 BACT for SF_6 Insulated Electrical Equipment

6.4.1 Step 1 – Identify All Available Control Technologies

The first step of the Top-Down BACT analysis is to identify all feasible control technologies.

The RBLC Database was reviewed for fugitives in SF_6 service. However, the only "limits" provided in the search results were on lb/hr or tpy basis, which is not comparable to other sites since those numbers are dependent on facility size and/or equipment counts and are not a true "BACT" limit.

One technology is the use of state-of-the-art SF_6 technology with leak detection to limit fugitive emissions. In comparison to older SF_6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

One alternative considered in this analysis is to substitute another, non-greenhouse-gas substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NTIS) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6*. However, there is no replacement gas that is immediately available for use as an SF_6-substitute ("drop-in gas") in electric utility equipment. For gas insulated circuit breakers, there are still significant questions concerning the performance of gases other than pure SF_6[6].

[6] L.G. Christophorous, J.K. Olthoff, and D.S. Green, *Gases for Electric Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6*, NIST Technical Note 1425, Nov. 1997.

6.4.2 Step 2 – Eliminate Technically Infeasible Options

According to the report NTIS Technical Note 1425, SF_6 is a superior dielectric gas for nearly all high voltage applications. It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6-insulated equipment. The report concluded that although "...various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture... it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore there are currently no technically feasible options besides use of SF_6.

6.4.3 Step 3 – Rank Remaining Control Technologies

The use of state-of-the-art SF_6 technology with leak detection to limit fugitive emissions is the highest ranked control technology that is technically feasible for this application.

6.4.4 Step 4 – Evaluate Most Effective Controls and Document Results

Energy, environmental, or economic impacts were not addressed in this analysis because the use of alternative, non-greenhouse-gas substance for SF_6 as the dielectric material in circuit breakers is not technically feasible.

6.4.5 Step 5 – Select BACT

Based on this top-down analysis, Apex concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection would be the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers. The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will bring potential fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF_6 gas.

Apex will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use. Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of 40 CFR Part 98, Subpart DD.

6.5 BACT Analysis for Natural Gas Fugitives

6.5.1 Step 1 – Identify All Available Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies.

The RBLC Database was reviewed for fugitives in natural gas service. However, the only "limits" provided in the search results were on lb/hr or tpy basis, which is not comparable to other sites since those numbers are dependent on facility size and/or equipment counts and are not a true "BACT" limit. Following is a description of other identified control technologies:

- Implementation of a leak detection and repair (LDAR) program using a vapor analyzer or other organic vapor sensing technology to monitor fugitive components for leaks on a set basis;
- Implementation of alternative monitoring using infrared (IR) or other remote sensing technology; and/or
- Implementation of an audio/visual/olfactory (AVO) (i.e., sensory) leak detection program.

6.5.2 Step 2 – Eliminate Technically Infeasible Options

All options identified in Step 1 are considered technically feasible and therefore need to be considered in Step 3 of the top-down BACT analysis.

6.5.3 Step 3 – Rank Remaining Control Technologies

An AVO program is associated with 97% control efficiencies for valves and flanges since equipment in natural gas service can be considered an odorous compound due to the mercaptans in the natural gas stream.

The implementation of an LDAR program for equipment in natural gas service can achieve a control efficiency of up to 97% for valves and flanges (including pressure relief devices), based on TCEQ's 28LAER. Additionally, the EPA has allowed the use of alternative monitoring using IR remote sensing technology as an alternative to Method 21 monitoring.

6.5.4 Step 4 – Evaluate Most Effective Controls and Document Results

All of the identified control technologies are associated with the same control efficiencies. However, due to the very low VOC content in the natural gas, the Apex power plant would not be subject to any LDAR (or alternative equivalent) program. Therefore, if implemented, these programs would be due solely to GHG emissions. LDAR programs (and their remote sensing alternatives) are costly to implement and have high costs on an ongoing basis. All of the identified control technologies are associated with the same control efficiencies; however, an AVO program would be a more cost-effective means of achieving the same result.

6.5.5 Step 5 – Select BACT

Apex proposes an AVO program with daily walk-through inspections as BACT for fugitive equipment in natural gas service.

6.6 Auxiliary Boiler BACT Analysis

One nominally rated 108.4 MMBtu/hr auxiliary boiler (EPN AUXBLR) will be utilized to facilitate startup of the combined cycle units. The auxiliary boiler's firing will be limited to 94,958.4 MMBtu per year which is equivalent to 10% of the maximum annual capacity.

6.6.1 Step 1: Identify All Available Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. The following technologies were identified as potential control options for boilers:

- Use of low carbon fuels – the auxiliary boiler will utilize natural gas which is the lowest carbon fuel available at the Neches Station. Therefore, formation of CO_2 from combustion of the fuel will be minimized.
- Energy efficient processes, practices, and designs – good operating and maintenance practices for the boiler include following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing in the combustion zone; and maintain the proper air/fuel ratio so that sufficient oxygen is provided to provide complete combustion of the fuel while at the same time preventing introduction of more air than is necessary into the boiler. Additionally, the auxiliary boiler is designed for a thermal energy efficiency of approximately 80%. The energy efficient design of the boiler includes insulation to retain heat within the boiler and a computerized process control system that will optimize the fuel/air mixture and limit excess air in the boiler.
- Low annual capacity factor – the auxiliary boiler's firing will be limited to 10% of the maximum annual capacity
- CCS

6.6.2 Step 2: Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable. All options are considered technically feasible.

6.6.3 Step 3: Rank Remaining Control Technologies

CCS control technology, energy efficient processes, practices, and designs, and use of low carbon fuels are being ranked by most efficient control method in Step 3 of the top-down BACT analysis as follows:

- CCS
- Use of low carbon fuels
- Energy efficient processes, practices, and designs
- Low annual capacity factor – the auxiliary boiler's firing will be limited to 10% of the maximum annual capacity

CCS technology may be associated with a potential 90% capture efficiency, making it a more effective control technology than the low carbon fuels, energy efficient processes, practices, and designs, and low annual capacity factor. No ranking for the use of low carbon fuels, the energy efficient processes, practices, and designs, and the low annual capacity factor are necessary as they are all being proposed for the auxiliary boiler.

6.6.4 Step 4: Evaluate Most Effective Controls and Document Results

As stated in Sections 6.2.4 and 6.3.4, CCS is not economically feasible for CO_2 emissions from the turbines and associated HRSG/DB. Since the CO_2 emissions from the auxiliary boiler is less than 0.02% of the CO_2 emissions generated from the turbines and associated HRSG/DB, using a CCS to control CO_2 emissions from the auxiliary boiler will also be determined economically infeasible. Therefore, CCS is not considered for this project.

Because the energy efficient processes, practices, and designs, use of low carbon fuels, good operating practices, and low annual capacity factor discussed in Section 6.6.1 of this application are being proposed for this project, an examination of the energy, environmental, and economic impacts of the efficiency designs is not necessary for this application.

6.6.5 Step 5: Select BACT

Based on this top-down analysis, Apex concludes that the use of natural gas as a low carbon fuel, good operating and maintenance practices, energy efficient design, and low annual capacity is selected as BACT for the auxiliary boiler. With the limited annual operation of the auxiliary boiler, the total CO_2e emissions from the boiler are 0.27% of the total site wide emissions.

Among other recently issued or currently pending GHG permits, the Wolverine Power Supply Cooperative permit[7] and the Palmdale Hybrid Power Project permit included BACT determinations for limited use, auxiliary boilers and heaters. The Wolverine permit included a 72.4 MMBtu/hr diesel-fired auxiliary boiler, limited to 4,000 hours operation per year. The permit listed BACT for GHG for the auxiliary boiler to incorporate energy efficient equipment wherever practical in the design of the auxiliary boiler. The Wolverine permit did not include an output based BACT limit for the auxiliary boiler.

The application for the Palmdale Hybrid Power Project (PHPP) was submitted in May 2011 and a draft permit was issued by the Antelope Valley Air Quality Management District in August 2011. The PHPP application proposed the construction of a power plant utilizing natural gas fired combustion turbine combined cycle generators located in Palmdale, California. The project also included a 110 MMBtu/hr natural-gas-fired auxiliary boiler, limited to 500 hours per year operation, and a 40 MMBtu/hr natural-gas-fired heater, limited to 1,000 hours per year operation. The Palmdale Permit listed BACT

[7] Wolverine Power Supply Cooperative permit application, http://www.deq.state.mi.us/aps/downloads/permits/CFPP/2007/317-07/2011%20GHG%20BACT%20Analysis.pdf, pg. 3-14, March 2011

for GHG for the auxiliary boiler and heater as annual tune-ups. The Palmdale Permit did not include an output based BACT limit for the auxiliary boiler or heater.

Therefore, Apex proposed BACT is consistent with other recent permits for similar facilities.

6.7 BACT for Firewater Pump Engine

The Apex site will be equipped with a diesel-fired firewater pump engine that will be used to supply water in cases of fire or other emergencies.

6.7.1 Step 1: Identify All Available Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. The following technologies were identified as potential control options for firewater pump engines:

- Engine options and fuel source – engine options include engines powered with electricity, natural gas, or liquid fuel, such as gasoline or fuel oil;
- Use of good operating and maintenance practices – operating with recommended fuel to air ratio recommended by the manufacturer, and appropriate maintenance of equipment, such as periodic readiness testing.
- Low annual capacity factor – the firewater pump engine will be limited to 100 hours non-emergency operation per year for purposes of maintenance checks and readiness testing.

6.7.2 Step 2: Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable. The purpose of the engines is to provide water in a case of fire. Electricity and natural gas may not be available during a fire emergency and therefore cannot be used as an energy source for the firewater pump engine.

The engines must be powered by a liquid fuel that can be stored on-site in a tank and supplied to the engines on demand, such as motor gasoline or diesel. The default CO_2 emission factors for gasoline and diesel are very similar, 70.22 kg/MMBtu for gasoline and 73.96 kg/MMBtu for No. 2 diesel. Diesel fuel has a much lower volatility than gasoline and can be stored for longer periods of time. Therefore, diesel is typically the chosen fuel for firewater pump engines.

Because of the need to store the firewater pump engine fuel on-site and the ability to store diesel for longer periods of time than gasoline, it is technically infeasible to utilize a lower carbon fuel than diesel.

The use of good operating and maintenance practices is technically feasible for the firewater pump engine. Apex will employ a Tier III compliance engine (MACT ZZZZ and NSPS IIII) as a firewater pump. Also, a low annual capacity factor for the engine is technically feasible since the engine will only be operated in non-emergencies either for readiness testing or for actual emergencies.

6.7.3 Step 3: Rank Remaining Control Technologies

Since the remaining technically feasible processes, practices, and designs discussed in Section 6.7.2 of this application for the firewater pump engine are being proposed for the engines, a ranking of the control technologies is not necessary for this application.

6.7.4 Step 4: Evaluate Most Effective Controls and Document Results

Since the remaining technically feasible processes, practices, and designs discussed in Section 6.7.2 of this application for the firewater pump engine are being proposed for the engines, an evaluation of the most effective controls is not necessary for this application.

6.7.5 Step 5: Select BACT

As a result of this analysis, appropriate operation of the engine through proper fuel to air ratios and maintenance based on recommended readiness testing and low annual hours of operation are selected as BACT for the proposed engine.

SECTION 7
OTHER PSD REQUIREMENTS

7.1 Impacts Analysis

An impacts analysis is not being provided with this application for GHG emissions per EPA's recommendations below:

> *Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause contribute to a violation of the NAAQS are not applicable to GHGs. Therefore, there is no requirement to conduct dispersion modeling or ambient monitoring for CO_2 or GHGs.*[8]

7.2 GHG Preconstruction Monitoring

A pre-construction monitoring analysis for GHG emissions is not being provided with this application for GHG emissions per EPA's recommendations below:

> *EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs.9*

7.3 Additional Impacts Analysis

A PSD additional impacts analysis is not being provided for GHG emissions with this application per EPA's recommendations below:

> *Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG*

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[8] EPA, *PSD and Title V Permitting Guidance For Greenhouse Gases* pp. 48-49.
[9] *Id.* at 49.

source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.[10]

[10] EPA, *PSD and Title V Permitting Guidance For Greenhouse Gases p.* 48.

SECTION 8
PROPOSED GHG MONITORING PROVISIONS

Apex proposes to monitor CO_2 emissions by monitoring the quantity of fuel combusted in the turbines and heat recovery steam generators and performing periodic fuel sampling as specified in 40 CFR Part 75.10(3)(ii) (refer to procedure below). Results of the fuel sampling will be used to calculate a site-specific F_C factor, and that factor will be used in the equation below to calculate CO_2 mass emissions.

The Apex natural gas-fired turbines will comply with the fuel flow metering and Gross Calorific Value (GCV) sampling requirements of 40 CFR Part 75, Appendix D. The site-specific F_C factor will be determined using the ultimate analysis and Gross Calorific Value in equation F-7b of 40 CFR Part 75, Appendix F. The site-specific F_C factor will be re-determined annually in accordance with 40 CFR Part 75, Appendix F, §3.3.6.

The procedure for estimating CO_2 Emissions specified in 40 CFR Part 75.10(3)(ii) is as follows:

Affected gas-fired and oil-fired units may use the following equation:

$$W_{CO_2} = \left(\frac{F_C * H * U_f * MW_{CO_2}}{2000}\right)$$

Where:

W_{CO2} = CO_2 emitted from combustion, tons/yr.

MW_{CO2} = Molecular weight of carbon dioxide, 44.0 lb/lb-mole.

F_C = Carbon based F-factor, 1040 scf/MMBtu for natural gas.

H = Annual heat input in MMBtu.

U_f = 1/385 scf CO_2/lb-mole at 14.7 psia and 68 °F.

The requirements for fuel flow monitoring and quality assurance in 40 CFR Part 75 Appendix D are:

- Fuel flow meter: meet an accuracy of 2.0 %, required to be tested once each calendar quarter (40 CFR Part 75, Appendix D, §2.1.5 and §2.1.6(a))
- Gross Calorific Value (GCV): determine the GCV of pipeline natural gas at least once per calendar month (40 CFR Part 75, Appendix D, §2.3.4.1)

This monitoring approach is consistent with the CO_2 reporting requirements of the GHG Mandatory Reporting Rule for Electricity Generation (40 CFR Part 98, Subpart D). Subpart D requires electric generating sources that report CO_2 emissions under 40 CFR Part 75 to report

CO_2 under 40 CFR Part 98 by converting CO_2 tons reported under Part 75 to metric tons. Also, the recently proposed NSPS Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units (40 CFR Part §60.5535(c)) allows electric generating units firing gaseous fuel and liquid fuel oil to determine CO_2 mass emissions by monitoring fuel combusted in the affected Electric Generating Unit and using a site specific F_C factor determined in accordance with 40 CFR Part 75, Appendix F. Therefore, Apex's proposed CO_2 monitoring method is consistent with the proposed NSPS Subpart TTTT.

Apex will also monitor the fuel flow to the auxiliary boiler. The fuel flow meter will be monitored for accuracy in accordance with industry standards.

APPENDIX A
EMISSION CALCULATIONS

This section contains emission calculations for GHG emission sources proposed at the Neches Station.

Scenario 1

Table A-1-1: Sitewide Summary of Emissions

Apex Texas Power, LLC

Neches Power Station

Emission Point Number	Description	Projected Emission Rate (tpy)					Reference Table
		CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	SF_6 (tpy)	CO_2e (tpy)	
E-ST1a E-ST2a E-ST3a E-ST4a	Simple Cycle Operation	1,525,376	28.3	2.9	-	1,526,948	Table A-1-3
	Turbine Startup/Sbutdown Activities	19,103	0.4	0.04	-	19,124	Table A-1-4
E-FWP	Firewater Pump Engine	19	0.0008	0.0002	-	19	Table A-8
FUG-NG	Natural Gas Fugitives	1.0	61.9	-	-	1,549	Table A-9
FUG-SF6	Sulfur Hexafluoride Fugitives	-	-	-	0.01	228	Table A-10
	TOTAL	**1,544,499**	**91**	**3**	**0.01**	**1,547,867**	**Sum of Above**

Scenario 1
Table A-1-2: Turbine Annual Firing Rate
Apex Texas Power, LLC
Neches Power Station

Mode	Heat Input/Unit [1, 2] (MMBtu/hr)	Number of Units	Operating Hours (Hours/yr)	Annual Firing Rate (MMBtu/yr)	Comments
Simple Cycle (Normal Operation)	2,565.81	4	2,500	25,658,119	Based on projected operation of four turbines at baseload and 59°F, 70% RH

Notes:

1. *Heat input is based on process design data that was provided by the manufacturer with margins.*
2. *Three margins were incorporated into the heat input:*
   a 3.3% design margin
   a 6.0% performance margin
   a 3.0% degradation margin

Sample calculations:

$$\text{Simple Cycle Firing Rate} = \frac{2{,}565.81\ \text{MMBtu}}{\text{hr-unit}} \times 4\ \text{units} \times \frac{2{,}500\ \text{hr}}{\text{yr}} = 25{,}658{,}119\ \text{MMBtu/yr}$$

Scenario 1
Table A-1-3: Simple Cycle Emissions
Apex Texas Power, LLC
Neches Power Station

Parameter	Values and Units		Comments
Annual Firing Rate	25,658,119 MMBtu/yr		Based on projected operation of four turbines at 80% load at 59°F, 70% RH
CO_2 Emission Factor[1]	118.9 lb CO_2/MMBtu		Note 1
CH_4 Emission Factor[2]	0.001 kg CH_4/MMBtu		Note 2
N_2O Emission Factor[2]	0.0001 kg N_2O/MMBtu		Note 2
Constituent	Emissions[4] (TPY)	Global Warming Potential Factor[3] (ton-CO_2/ton)	CO_2e Emissions (TPY)
CO_2	1,525,376	1	1,525,376
CH_4	28	25	707
N_2O	2.9	298	865
Total	**1,525,407**	--	**1,526,948**

Notes:

1. *Emission factor for CO_2 in natural gas from 40 CFR Part 75, Appendix G, Section 2.3. See sample calculations below.*
2. *Emission factors for CH_4 and N_2O in natural gas from 40 CFR Part 98, Table C-2.*
3. *Global Warming Potential Factors from Table A-1 of 40 CFR Part 98.*
4. *The final emission rate is based on the expected maximum annual firing rate for simple cycle mode.*

Sample calculations:

$$\text{Turbine } CO_2 = \frac{25{,}658{,}119 \text{ MMBtu}}{\text{yr}} \times \frac{118.9 \text{ lb}}{\text{MMBtu}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 1{,}525{,}376 \text{ tons/yr}$$

$$CO_2\text{e from } N_2O = \frac{2.9 \text{ ton}}{\text{yr}} \times \frac{298 \text{ ton } CO_2\text{e}}{\text{ton } N_2O} = 865 \text{ tons/yr}$$

Scenario 1
Table A-1-4: Startup/Shutdown Emissions
Apex Texas Power, LLC
Neches Power Station

Parameter	Values and Units		Comments
Unit Count	4		
Annual Firing Rate[1]	80,329 MMBtu/yr		Note 1
CO_2 Emission Factor[2]	118.9 lb CO_2/MMBtu		Note 2
CH_4 Emission Factor[3]	0.001 kg CH_4/MMBtu		Note 3
N_2O Emission Factor[4]	0.0001 kg N_2O/MMBtu		Note 3
Constituent	**Emissions (TPY)**	**Global Warming Potential Factor[3] (ton-CO_{2e}/ton)**	**CO_2e Emissions (TPY)**
CO_2	19,103	1	19,103
CH_4	0.4	25	9
N_2O	0.04	298	12
Total	**19,103**	--	**19,124**

Notes:

1. *Annual firing rate is based on fuel flow for each startup and shutdown, and the number of startup and shutdown per year for one turbine.*
2. *Emission factor for CO_2 in natural gas from 40 CFR Part 75, Appendix G, Section 2.3, Equation G-4. See sample calculations below.*
3. *Emission factors for CH_4 and N_2O in natural gas from 40 CFR Part 98, Table C-2.*
4. *Global Warming Potential Factors from Table A-1 of 40 CFR Part 98.*

Sample calculations:

$$\text{Turbine SU/SD } CO_2 = \frac{80{,}329 \text{ MMBtu}}{\text{yr}} \cdot \frac{118.9 \text{ lb}}{\text{MMBtu}} \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lb}} \cdot 4 \text{ trains} = 19{,}103 \text{ tons/yr}$$

$$CO_2\text{e from } N_2O = \frac{0.04 \text{ ton}}{\text{yr}} \cdot \frac{298 \text{ ton } CO_2\text{e}}{\text{ton } N_2O} = 12 \text{ tons/yr}$$

Scenario 1

Table A-1-5: Turbine BACT Output Limit

Apex Texas Power, LLC

Neches Power Station

Parameter	Values and Units	Comments
Gross Heat Rate (Simple)	11,592 Btu/kWh	Note 1
CO_2 Emission Factor	118.9 lb CO_2/MMBtu	Note 2
Simple Cycle BACT Output Limit		
Constituent	BACT Output Limit (lb CO_2/MWh)	BACT Output Limit (ton CO_2/MWh)
CO_2	1,378.27	**0.69**

Notes:

1. *Gross Heat Rates are at 80% Load, 59 °F, 70% RH.*
2. *Emission factor for CO_2 in natural gas from 40 CFR Part 75, Appendix G, Section 2.3, Equation G-4. See sample calculations below.*

Sample calculations:

$$CO_2 \text{ BACT Limit} = \frac{11{,}592 \text{ Btu}}{\text{kWh}} \cdot \frac{1{,}000 \text{ kWh}}{\text{MWh}} \cdot \frac{118.9 \text{ lb CO2}}{\text{MMBtu}} \cdot \frac{\text{MMBtu}}{10^6 \text{ Btu}} = 1{,}378 \text{ lb CO2/MWh}$$

Scenario 2

Phase 1: Table A-2-1a: Sitewide Summary of Emissions (Simple Cycle)

Apex Texas Power, LLC

Neches Power Station

Emission Point Number	Description	Projected Emission Rate (tpy)					Reference Table
		CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	SF_6 (tpy)	CO_2e (tpy)	
E-ST1a E-ST2a	Simple Cycle Operation	762,688	15	1.5	-	773,072	Table A-2-3
	Turbine Startup/Shutdown Activities	9,552	0.2	0.0	-		Table A-2-5a
E-FWP	Firewater Pump Engine	19	0.0	0.0	-	19	Table A-8
FUG-NG	Natural Gas Fugitives	1.0	61.9	-	-	1,549	Table A-9
FUG-SF6	Sulfur Hexafluoride Fugitives	-	-	-	0.0100	228	Table A-10
	TOTAL	**772,260**	77	**2**	**0.0100**	**774,868**	**Sum of Above**

Scenario 2

Phase 2: Table A-2-1b: Sitewide Summary of Emissions (Combined Cycle)

Apex Texas Power, LLC

Neches Power Station

Emission Point Number	Description	Projected Emission Rate (tpy)					Reference Table
		CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	SF_6 (tpy)	CO_2e (tpy)	
E-ST1b E-ST2b	Combined Cycle Operation[1]	3,197,800	60	6.0	-	3,201,088	Table A-2-4
E-AUXBLR	Auxiliary Boiler	5,554	0.2	0.1	-	5,589	Table A-2-7
E-FWP	Firewater Pump Engine	19	0.0	0.0	-	19	Table A-8
FUG-NG	Natural Gas Fugitives	1.0	61.9	-	-	1,549	Table A-9
FUG-SF6	Sulfur Hexafluoride Fugitives	-	-	-	0.0100	228	Table A-10
	TOTAL	**3,203,374**	**122**	**6**	**0.0100**	**3,208,472**	**Sum of Above**

Notes:

1. *GHG emissions during startup/shutdown of turbines are included in the proposed annual emissions for the turbines.*

Scenario 2

Table A-2-2: Turbine Annual Firing Rate

Apex Texas Power, LLC

Neches Power Station

Mode	Heat Input/Unit[1,2] (MMBtu/hr)	Number of Units	Operating Hours (Hours/yr)	Annual Firing Rate (MMBtu/yr)	Comments
Combined Cycle (Normal Operation)	3,070.19	2	8,760	53,789,729	Based on projected operation of Max Power
Simple Cycle (Normal Operation)	2,565.81	2	2,500	12,829,059	Based on projected operation of baseload at 59°F, 70% RH

Notes:

1. *Output and heat rate are based on process design data that was provided by the manufacturer, with margins.*
2. *Three margins were incorporated into the heat rate:*
   a 3.3% design margin
   a 6.0% performance margin
   a 3.0% degredation margin

Sample calculations:

$$\text{Combined Cycle Firing Rate} = \frac{3{,}070\ \text{MMBtu}}{\text{hr-unit}} \left| \frac{2\ \text{units}}{} \right| \frac{8{,}760\ \text{hr}}{\text{yr}} = 53{,}789{,}729\ \text{MMBtu/yr}$$

Scenario 2
Phase 1: Table A-2-3: Simple Cycle Emissions
Apex Texas Power, LLC
Neches Power Station

Parameter	Values and Units		Comments
Annual Firing Rate	12,829,059 MMBtu/yr		Based on projected operation of two turbines at 80% load at 59°F, 70% RH
CO_2 Emission Factor[1]	118.9 lb CO_2/MMBtu		Note 1
CH_4 Emission Factor[2]	0.001 kg CH_4/MMBtu		Note 2
N_2O Emission Factor[2]	0.0001 kg N_2O/MMBtu		Note 2
Constituent	Emissions[4] (TPY)	Global Warming Potential Factor[3] (ton-CO_{2e}/ton)	CO_2e Emissions (TPY)
CO_2	762,688	1	762,688
CH_4	15	25	375
N_2O	1.5	298	447
Total	**762,705**	--	**763,510**

Notes:
1. *Emission factor for CO_2 in natural gas from 40 CFR Part 75, Appendix G, Section 2.3. See sample calculations below.*
2. *Emission factors for CH_4 and N_2O in natural gas from 40 CFR Part 98, Table C-2.*
3. *Global Warming Potential Factors from Table A-1 of 40 CFR Part 98.*
4. *The final emission rate is based on the expected maximum annual firing rate for simple cycle mode.*

Sample calculations:

$$\text{Turbine } CO_2 = \frac{12{,}829{,}059 \text{ MMBtu}}{\text{yr}} \cdot \frac{118.9 \text{ lb}}{\text{MMBtu}} \cdot \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 762{,}688 \text{ tons/yr}$$

$$N_2O\ CO_2e = \frac{1.5 \text{ ton}}{\text{yr}} \cdot \frac{298 \text{ ton } CO_2e}{\text{ton } N_2O} = 447 \text{ tons/yr}$$

Scenario 2
Phase 2: Table A-2-4: Combined Cycle Emissions
Apex Texas Power, LLC
Neches Power Station

Parameter	Values and Units		Comments
Annual Firing Rate (Turbines & Duct Burners)	53,789,729 MMBtu/yr		From Table A-2
CO_2 Emission Factor[1]	118.9 lb CO_2/MMBtu		Note 1
CH_4 Emission Factor[2]	0.001 kg CH_4/MMBtu		Note 2
N_2O Emission Factor[2]	0.0001 kg N_2O/MMBtu		Note 2
Constituent	Emissions[4] (TPY)	Global Warming Potential Factor[3] (ton-CO_2/ton)	CO_2e Emissions (TPY)
CO_2	3,197,800	1	3,197,800
CH_4	60	25	1,500
N_2O	6.0	298	1,788
Total	**3,197,866**	--	**3,201,088**

Notes:

1. *Emission factor for CO_2 in natural gas from 40 CFR Part 75, Appendix G, Section 2.3, Equation G-4. See sample calculations below.*
2. *Emission factors for CH_4 and N_2O in natural gas from 40 CFR Part 98, Table C-2.*
3. *Global Warming Potential Factors from Table A-1 of 40 CFR Part 98.*
4. *The final emissions rate is based on the expected maximum annual firing rate for combined cycle mode.*

Sample calculations:

$$CO_2 \text{ Emission Factor} = \frac{1{,}040}{} \left| \frac{\text{scf}}{\text{MMBtu}} \right| \frac{\text{lb-mole}}{385 \text{ scf}} \left| \frac{44 \text{ lb } CO_2}{\text{lb-mole}} \right. = 118.9 \text{ lb CO2/MMBtu}$$

$$\text{Turbine } CO_2 = \frac{53{,}789{,}729 \text{ MMBtu}}{\text{yr}} \left| \frac{118.9 \text{ lb}}{\text{MMBtu}} \right| \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 3{,}197{,}799 \text{ tons/yr}$$

$$CO_2e_{\,N2O} = \frac{6 \text{ ton N2O}}{\text{yr}} \left| \frac{298 \text{ ton } CO_2e}{\text{ton } N_2O} \right. = 1{,}788 \text{ tons/yr}$$

Scenario 2

Phase 1: Table A-2-5a: Startup/Shutdown Emissions (Simple Cycle)

Apex Texas Power, LLC

Neches Power Station

Parameter	Values and Units		Comments
Train Count	2		
Annual Firing Rate[1]	80,329 MMBtu/yr		Note 1
CO_2 Emission Factor[2]	118.9 lb CO_2/MMBtu		Note 2
CH_4 Emission Factor[3]	0.001 kg CH_4/MMBtu		Note 3
N_2O Emission Factor[4]	0.0001 kg N_2O/MMBtu		Note 3
Constituent	Emissions (TPY)	Global Warming Potential Factor[3] (ton-CO_{2e}/ton)	CO_2e Emissions (TPY)
CO_2	9,552	1	9,552
CH_4	0.2	25	4
N_2O	0.02	298	6
Total	**9,552**	--	**9,562**

Notes:

1. *Annual firing rate is based on fuel flow for each startup and shutdown, and the number of startup and shutdown per year for one turbine.*
2. *Emission factor for CO_2 in natural gas from 40 CFR Part 75, Appendix G, Section 2.3, Equation G-4. See sample calculations below.*
3. *Emission factors for CH_4 and N_2O in natural gas from 40 CFR Part 98, Table C-2.*
4. *Global Warming Potential Factors from Table A-1 of 40 CFR Part 98.*

Sample calculations:

$$\text{Turbine SU/SD } CO_2 = \frac{80{,}329 \text{ MMBtu}}{\text{yr}} \left| \frac{118.9 \text{ lb}}{\text{MMBtu}} \right| \frac{1 \text{ ton}}{2{,}000 \text{ lb}} \left| \frac{2 \text{ trains}}{} \right. = 9{,}552 \text{ tons/yr}$$

$$CO_2\text{e from } N_2O = \frac{0.02 \text{ ton}}{\text{yr}} \left| \frac{298 \text{ ton } CO_2\text{e}}{\text{ton } N_2O} \right. = 6 \text{ tons/yr}$$

Scenario 2

Table A-2-6: Turbine BACT Output Limit

Apex Texas Power, LLC

Neches Power Station

Parameter	Values and Units	Comments
Gross Heat Rate (Simple)	11,592 Btu/kWh	Projected operation of 80% load at 59°F, 70% RH
Gross Heat Rate (Combined)	8,191 Btu/kWh	Max Power, ISO Conditions Case
CO_2 Emission Factor[1]	118.9 lb CO_2/MMBtu	
Simple Cycle BACT Output Limit		
Constituent	BACT Output Limit (lb CO_2/MWh)	BACT Output Limit (ton CO_2/MWh)
CO_2	1,378.27	**0.69**
Combined Cycle BACT Output Limit		
Constituent	BACT Output Limit (lb CO_2/MWh)	BACT Output Limit (ton CO_2/MWh)
CO_2	973.96	**0.49**

Notes:

1. *Emission factor for CO_2 in natural gas from 40 CFR Part 75, Appendix G, Section 2.3, Equation G-4. See sample calculations below.*

Sample calculations (combined cycle):

$$CO_2 \text{ BACT Limit} = \frac{.0082 \text{ MMBtu}}{\text{kWh}} \times \frac{1{,}000 \text{ kWh}}{\text{MWhr}} \times \frac{118.9 \text{ lb CO2}}{\text{MMBtu}} = 973.96 \text{ lb CO2/MWh}$$

Scenario 2
Table A-2-7: Auxiliary Boiler Emissions
Apex Texas Power, LLC
Neches Power Station

Parameter	Values and Units		Comments
Boiler Count	1		
Annual Firing Rate	94,958 MMBtu/yr		10% Max Annual Capacity
CO_2 Emission Factor[1]	53.06 kg CO_2/MMBtu		Note 1
CH_4 Emission Factor[2]	0.001 kg CH_4/MMBtu		Note 2
N_2O Emission Factor[2]	0.0001 kg N_2O/MMBtu		Note 2
Constituent	Emissions[4] (TPY)	Global Warming Potential Factor[3] (ton-CO_2e/ton)	CO_2e Emissions (TPY)
CO_2	5,554	1	5,554
CH_4	0.2	25	5
N_2O	0.1	298	30
Total	**5,554**	--	**5,589**

Notes:

1. *Emission factor for CO_2 in natural gas from 40 CFR Part 98, Table C-1.*
2. *Emission factors for CH_4 and N_2O in natural gas from 40 CFR Part 98, Table C-2.*
3. *Global Warming Potential Factors from Table A-1 of 40 CFR Part 98.*
4. *The final emissions are based on 10% of the expected maximum annual capacity.*

Sample calculations:

$$\text{Boiler } CO_2 = \frac{94{,}958 \text{ MMBtu}}{\text{yr}} \left| \frac{53.06 \text{ kg}}{\text{MMBtu}} \right| \frac{2.2046 \text{ lb}}{\text{kg}} \left| \frac{1 \text{ ton}}{2{,}000 \text{ lb}} \right. = 5{,}554 \text{ tons/yr}$$

$$N_2O\ CO_2e = \frac{0.1 \text{ ton}}{\text{yr}} \left| \frac{298 \text{ ton } CO_2e}{\text{ton } N_2O} \right. = 30 \text{ tons/yr}$$

Table A-8: Fire Water Pump Emissions
Apex Texas Power, LLC
Neches Power Station

Parameter	Values and Units	Comments
Annual Operating Schedule	100 hrs/yr	NSPS Subpart IIII Limit
Power Rating	360 HP	Design Data
Assumed Engine Efficiency	40 %	Conservatively assume engines have efficiency ratings of 40%
Max. Hourly Heat Input	2.29 MMBtu/hr	
Annual Heat Input	229 MMBtu/yr	
CO_2 Emission Factor [1,2]	73.96 kg/MMBtu	40 CFR Part 98, Table C-1 for No. 2 diesel
CH_4 Emission Factor [2]	3.00E-03 kg/MMBtu	40 CFR Part 98, Table C-2 for petroleum fuel
N_2O Emission Factor [2]	6.00E-04 kg/MMBtu	40 CFR Part 98, Table C-2 for petroleum fuel

Constituent	Emissions (TPY)	Global Warming Potential Factor[3] (ton-CO_{2e}/ton)	CO_2e Emissions (TPY)
CO_2	19	1	19
CH_4	0.0008	25	0.02
N_2O	0.0002	298	0.05
Total	**19**	--	19

Notes:

1. *Default high heat based on Table C-1 of 40 CFR Part 98 Mandatory Greenhouse Gas Reporting.*
2. *GHG factors based on Tables C-1 and C-2 of 40 CFR Part 98 Mandatory Greenhouse Gas Reporting.*
3. *Global Warming Potential factors based on Table A-1 of 40 CFR Part 98 Mandatory Greenhouse Gas Reporting.*

Sample calculations:

$$\text{Annual Heat Input} = \frac{360\text{ HP}}{\text{hr}} \left| \frac{0.0025\text{ MMBtu}}{\text{HP}} \right| \frac{-}{40\%\text{ Efficiency}} \left| \frac{100\text{ hr}}{\text{yr}} \right. = 229\text{ MMBtu/yr}$$

$$\text{Firewater Pump } CO_2 = \frac{229\text{ MMBtu}}{\text{yr}} \left| \frac{73.96\text{ kg}}{\text{MMBtu}} \right| \frac{2.2046\text{ lb}}{\text{kg}} \left| \frac{1\text{ ton CO2}}{2{,}000\text{ lbs}} \right. = 19\text{ tons/yr}$$

Table A-9: Natural Gas Piping Fugitive Emissions
Apex Texas Power, LLC
Neches Power Station

Components	Fluid State	Count	Emission Factor[1] (scf/hr/comp)	Yearly Natural Gas Emissions (scf/yr)
Valve	Gas/Vapor	1440	0.121	1,526,342.40
Flange	Gas/Vapor	5760	0.017	857,779.20
Compressors	Gas/Vapor	8	13.3	932,064.00
Pressure Relief Valve	Gas/Vapor	24	0.193	40,576.32
Sampling Connections	Gas/Vapor	24	0.3	63,072.00
Total	--	**7232**	--	**3,419,833.92**
Constituent	Composition (vol%)	Emissions (TPY)	Global Warming Potential Factor[2] (ton-CO_2/ton)	CO_2e Emissions (TPY)
CO_2	0.09%	1	1	1
CH_4	87.09%	61.9	25	1,548
Total	--	--	26	**1,549**

Notes:

1. *Emission factors from Table W-1A of 40 CFR Part 98 for Western U.S.Emission Factor for sampling connection based on "Other" for light crude service.*
2. *Global Warming Potential Factors from Table A-1 of 40 CFR Part 98 (from 78 FR 71948, Nov. 29, 2013).*

Sample calculations:

$$\text{NG Emissions} = \frac{1440\text{ comp}}{} \left| \frac{0.121\text{ scf}}{\text{hr-comp}} \right| \frac{8{,}760\text{ hr}}{\text{yr}} = 1{,}526{,}342\text{ scf/yr}$$

$$CH_4\text{ Emissions} = \frac{1{,}526{,}342\text{ scf NG}}{\text{yr}} \left| \frac{0.871\text{ scf CH4}}{\text{scf NG}} \right| \frac{1\text{ lbmol}}{385.5\text{ scf}} \left| \frac{16\text{ lb CH4}}{\text{lbmol CH4}} \right| \frac{1\text{ ton}}{2000\text{ lb}} = 61.9\text{ tons/yr}$$

$$CO_2e\text{ from }CH_4 = \frac{61.9\text{ ton}}{\text{yr}} \left| \frac{25\text{ ton }CO_2e}{\text{ton }CH_4} \right. = 1547.5\text{ tons/yr}$$

Table A-10: SF_6 Fugitive Emissions
Apex Texas Power, LLC
Neches Power Station

Parameter	Values and Units		Comments
Insulated SF_6 Capacity	4,000 lb SF_6		
Estimated Annual SF_6 Leak Rate	0.5% by weight		
Constituent	Emissions (TPY)	Global Warming Potential Factor[1] (ton-CO_{2e}/ton)	CO_2e Emissions (TPY)
SF_6	0.01	22,800	228
Total	0.01	--	**228**

Notes:

1. *Global Warming Potential Factors from Table A-1 of 40 CFR Part 98.*

Sample calculations:

$$SF_6 \text{ Emissions} = \frac{4000 \text{ lb SF6}}{} \left| \frac{0.005 \text{ lb SF6 leaked}}{\text{lb SF6-yr}} \right| \frac{1 \text{ ton}}{2000 \text{ lb}} = 0.01 \text{ tons/yr}$$

$$CO_2e \text{ from } SF_6 = \frac{0.01 \text{ ton}}{\text{yr}} \left| \frac{22{,}800 \text{ ton } CO_2e}{\text{ton } SF_6} \right. = 228 \text{ ton/yr}$$