Exelon Generation

September 12, 2014

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

Re: Application for a Prevention of Significant Deterioration Air Quality Permit for Greenhouse Gas Emissions
PSD-TX-1410-GHG
Colorado Bend II
Wharton, Wharton County, Texas

Mr. Robinson:

Exelon Power, on behalf of Colorado Bend II Power, LLC, hereby submits this application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions for the addition of two new natural gas fired combined cycle electric generating combustion turbines to be located at the existing Colorado Bend Energy Center in Wharton, Wharton County, Texas. To the extent practicable, the proposed project will make use of existing plant infrastructure, but will be an independent regulated source with a unique Texas regulated entity reference number (or RN).

Note that the PSD permit application for non-GHG pollutants for this project was originally submitted under the company name of CER-Colorado Bend Energy Partners, LP to the Texas Commission on Environmental Quality (TCEQ) on April 18, 2014. In addition to this PSD GHG permit application, a revised PSD non-GHG pollutants permit application is being submitted to the TCEQ under the current company name of Colorado Bend II Power, LLC.

General information for the application is provided on the TCEQ Form PI-1 - General Application for Air Preconstruction Permit and Amendments. The U.S. Environmental Protection Agency's (EPA) document entitled "PSD and Title V Permitting Guidance For Greenhouse Gases", dated November 2010 and March 2011, was utilized as a guide for preparation of the attached application. The supporting Biological Assessment and Cultural Resources Assessment for the project will be submitted at a later date.

Colorado Bend II Power is committed to working closely with EPA Region 6 to get the application review completed as expeditiously as possible. We will be contacting your staff soon after submittal of this application to arrange a meeting to review the application and answer any questions that your team may have developed after initially reading our application.

Should you have any questions regarding this application, please contact me at albert.hatton@exeloncorp.com or by telephone at (610) 765 5316 or Mr. Larry Moon, P.E. of Zephyr Environmental Corporation at lmoon@zephyrenv.com or by telephone at (512) 879-6619.

Sincerely,

Al M Hatton III

Albert M. Hatton III
Senior Environmental Project Manager
Exelon Power

Enclosure

cc: Ms. Ashley K. Wadick, Regional Director, TCEQ Region 12, Houston
Mr. Mike Wilson, Director, Air Permits Division, TCEQ
Ms. Stephanie Kordzi, EPA Region 6 (electronic copy by email)
Mr. Larry Moon, P.E., Zephyr Environmental Corporation

PREVENTION OF SIGNIFICANT DETERIORATION GREENHOUSE GAS PERMIT APPLICATION FOR A COMBINED CYCLE POWER PROJECT EXPANSION AT THE COLORADO BEND ENERGY CENTER WHARTON COUNTY, TEXAS

SUBMITTED TO:

ENVIRONMENTAL PROTECTION AGENCY
REGION 6
MULTIMEDIA PLANNING AND PERMITTING DIVISION
FOUNTAIN PLACE 12TH FLOOR, SUITE 1200
1445 ROSS AVENUE
DALLAS, TEXAS 75202-2733

SUBMITTED BY:

COLORADO BEND II POWER, LLC
PO BOX 311
WHARTON, TEXAS 77488-0311

PREPARED BY:

ZEPHYR ENVIRONMENTAL CORPORATION
TEXAS REGISTERED ENGINEERING FIRM F-102
2600 VIA FORTUNA, SUITE 450
AUSTIN, TEXAS 78746

SEPTEMBER 2014

zephyr

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APPENDICES

1.0 INTRODUCTION

Colorado Bend II Power, LLC (Colorado Bend II Power) is hereby submitting this application for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) air quality permit to construct and operate two new combined-cycle electric generating units, referenced as the Colorado Bend II project, at the existing Colorado Bend Energy Center (CBEC) located in Wharton, Wharton County, Texas. To the extent practicable, the proposed project will make use of existing plant infrastructure, but will be an independent regulated source with a unique Texas regulated entity reference number (or RN).

The proposed project will consist of two natural gas-fired combustion turbines (CTs), each exhausting to a heat recovery steam generator (HRSG), equipped with natural gas-fired duct burners (DBs), to produce steam to drive a shared steam turbine. The specific combustion turbine model being considered for the project is the General Electric (GE) 7HA.02, which has a maximum base-load electric power output of approximately 328 MW. The total maximum electric power output from the combined cycle project (i.e., two combined cycle units) with DB firing and the steam turbine will be approximately 1,157 MW.

Note that the PSD permit application for non-GHG pollutants for this project was originally submitted under the company name of CER-Colorado Bend Energy Partners, LP to the Texas Commission on Environmental Quality (TCEQ) on April 18, 2014. In addition to this PSD GHG permit application, a revised permit application for non-GHG pollutants is being submitted to the TCEQ under the current company name of Colorado Bend II Power, LLC.

In accordance with the U. S. Environmental Protection Agency (EPA) memo entitled "Next Steps and Preliminary Views on the Application of Clean Air Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in Utility Air Regulatory Group v. Environmental Protection Agency" dated July 24, 2014, the proposed project triggers BACT review for GHG emissions because the calculated net project increase of GHG emissions is greater than 75,000 tons per year (tpy) CO_2e and the proposed project is triggering PSD permitting for pollutants other than GHG.

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

Important Note: The agency requires that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued and no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: Colorado Bend II Power, LLC		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: Gerome Randle		
Title: Vice President		
Mailing Address: Exelon Power; 325 N Saint Paul Street, Suite 2650		
City: Dallas	State: TX	ZIP Code: 75201
Telephone No.: 972-813-6154	Fax No.:	E-mail Address: Gerome.Randle3@exeloncorp.com
C. Technical Contact Name: Albert M. Hatton III		
Title: Senior Environmental Project Manager		
Company Name: Exelon Power		
Mailing Address: 300 Exelon Way		
City: Kennett Square	State: PA	ZIP Code: 19348
Telephone No.: 610-765-5316	Fax No.:	E-mail Address: Albert.hatton@exeloncorp.com
D. Site Name: Colorado Bend II		
E. Area Name/Type of Facility: Electric Generating Facility		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Generation of Electricity		
Principal Standard Industrial Classification Code (SIC): 4911		
Principal North American Industry Classification System (NAICS): 221112		
G. Projected Start of Construction Date: March 18, 2015		
Projected Start of Operation Date: March 9, 2017		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 3863 S State Highway 60		
City/Town: Wharton	County: Wharton	ZIP Code: 77488-8456
Latitude (nearest second): 29° 17' 19.6"N	Longitude (nearest second): 96° 3' 57.5"W	

I.	**Applicant Information (continued)**	
I.	Account Identification Number (leave blank if new site or facility): WBA002B	
J.	Core Data Form.	
Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L).		☐ YES ☒ NO
K.	Customer Reference Number (CN): TBD	
L.	Regulated Entity Number (RN): TBD	
II.	**General Information**	
A.	Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.	☐ YES ☒ NO
B.	Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES ☒ NO
C.	Number of New Jobs: 15	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: Senator Glenn Hegar		District No.:18
State Representative: Representative Phil Stephenson		District No.:85
III.	**Type of Permit Action Requested**	
A.	Mark the appropriate box indicating what type of action is requested.	
☒ Initial ☐ Amendment ☐ Revision (30 TAC 116.116(e) ☐ Change of Location ☐ Relocation		
B.	Permit Number (if existing):	
C.	Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)*	
☒ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit		
☒ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source		
☐ Other:		
D.	Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

III.	**Type of Permit Action Requested *(continued)***		
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.0			☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO", attach detailed information.			☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?			☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.			
List: N/A			
G. Are you permitting planned maintenance, startup, and shutdown emissions? If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.			☒ YES ☐ NO
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) Is this facility located at a site required to obtain a federal operating permit? If Yes, list all associated permit number(s), attach pages as needed).			☒ YES ☐ NO ☐ To be determined
Associated Permit No (s.): Will apply for a new Title V Permit			
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.			
☐ FOP Significant Revision	☐ FOP Minor	☐ Application for an FOP Revision	
☐ Operational Flexibility/Off-Permit Notification		☐ Streamlined Revision for GOP	
☒ To be Determined		☐ None	

III. Type of Permit Action Requested *(continued)*		
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*		
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***		
☐ GOP Issued	☐ GOP application/revision application submitted or under APD review	
☒ SOP Issued	☐ SOP application/revision application submitted or under APD review	
IV. Public Notice Applicability		
A. Is this a new permit application or a change of location application?		☒ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.		☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?		☒ YES ☐ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?		☐ YES ☒ NO
If Yes, list the affected state(s) and/or Class I Area(s).		
List:		
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.		
1. Is there any change in character of emissions in this application?		☐ YES ☐ NO
2. Is there a new air contaminant in this application?		☐ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?		☐ YES ☐ NO
F. List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***		
Volatile Organic Compounds (VOC):		
Sulfur Dioxide (SO2):		
Carbon Monoxide (CO):		
Nitrogen Oxides (NOx):		
Particulate Matter (PM):		
PM 10 microns or less (PM10):		
PM 2.5 microns or less (PM2.5):		
Lead (Pb):		
Hazardous Air Pollutants (HAPs):		
Other speciated air contaminants not listed above: CO2e: 3,976,647 tpy		

TCEQ

V. Public Notice Information *(complete if applicable)*		
A. Public Notice Contact Name: Albert M. Hatton III		
Title: Senior Environmental Project Manager		
Mailing Address: 300 Exelon Way		
City: Kennett Square	State: PA	ZIP Code: 19348
B. Name of the Public Place: N/A		
Physical Address *(No P.O. Boxes)*:		
City:	County:	ZIP Code:
The public place has granted authorization to place the application for public viewing and copying. N/A		☐ YES ☐ NO
The public place has internet access available for the public. N/A		☐ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable: Phillip Spenrath		
Mailing Address: 309 E. Milam St., Suite 600		
City: Wharton	State: TX	ZIP Code: 77488
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located.		
Chief Executive: Mayor Domingo Montalvo, Jr.		
Mailing Address: 120 East Caney Street		
City: Wharton	State: TX	ZIP Code: 77488
Name of the Indian Governing Body: N/A		
Mailing Address:		
City:	State:	ZIP Code:

V. Public Notice Information *(complete if applicable) (continued)*	
C. Concrete Batch Plants, PSD, and Nonattainment Permits	
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. *(continued)*	
Name of the Federal Land Manager(s): N/A	
D. Bilingual Notice N/A	
Is a bilingual program required by the Texas Education Code in the School District?	☐ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?	☐ YES ☐ NO
If Yes, list which languages are required by the bilingual program?	
VI. Small Business Classification *(Required)*	
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?	☐ YES ☒ NO
B. Is the site a major stationary source for federal air quality permitting?	☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☐ YES ☒ NO
VII. Technical Information	
A. The following information must be submitted with your Form PI-1 ***(this is just a checklist to make sure you have included everything)***	
1. ☒ Current Area Map	
2. ☒ Plot Plan	
3. ☐ Existing Authorizations	
4. ☒ Process Flow Diagram	
5. ☒ Process Description	
6. ☒ Maximum Emissions Data and Calculations	
7. ☐ Air Permit Application Tables	
a. ☐ Table 1(a) (Form 10153) entitled, Emission Point Summary	
b. ☐ Table 2 (Form 10155) entitled, Material Balance	
c. ☐ Other equipment, process or control device tables	
B. Are any schools located within 3,000 feet of this facility? N/A	☐ YES ☐ NO

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VII.	**Technical Information**		
C.	Maximum Operating Schedule:		
Hour(s): 24	Day(s): 7	Week(s): 52	Year(s): 8,760 hr/year
Seasonal Operation? If Yes, please describe in the space provide below.			☐ YES ☒ NO
D.	Have the planned MSS emissions been previously submitted as part of an emissions inventory?		☒ YES ☐ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.			
	SEE APPENDIX A OF APPLICATION		
E.	Does this application involve any air contaminants for which a disaster review is required? N/A		☐ YES ☐ NO
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)? N/A		☐ YES ☐ NO
VIII.	**State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*		
A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?		☒ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?		☒ YES ☐ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?		☒ YES ☐ NO
D.	Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?		☒ YES ☐ NO
IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*		
A.	Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?		☒ YES ☐ NO
B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?		☐ YES ☒ NO

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D.	Do nonattainment permitting requirements apply to this application? N/A for GHG	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
Is the estimated capital cost of the project greater than $2 million dollars? N/A		☐ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.		
XI.	**Permit Fee Information**	
Check, Money Order, Transaction Number ,ePay Voucher Number: 81005988		Fee Amount: N/A
Paid online? N/A		☐ YES ☐ NO
Company name on check: N/A		
Is a copy of the check or money order attached to the original submittal of this application?		☐ YES ☐ NO ☒ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?		☐ YES ☐ NO ☒ N/A

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XII. Delinquent Fees and Penalties
This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.

XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: Gerome Randle
Signature: *Original Signature Required*
Date: 9/11/2014

2.0 PROJECT OVERVIEW AND DESCRIPTION

2.1 INTRODUCTION

With this application, Colorado Bend II Power is seeking authorization to construct a combined cycle electric generating project at the CBEC. The power generating equipment and ancillary equipment that will be constructed as part of the project and that are sources of GHG emissions at the site are summarized below:

- Two identical combined-cycle, natural gas-fired combustion turbines equipped with dry low-NO_x (DLN) combustors;
- Two natural gas-fired duct burner systems serving the HRSGs associated with the combustion turbines;
- Two small natural gas-fired dew point heaters;
- A natural gas-fired auxiliary boiler;
- A diesel fuel-fired emergency generator engine;
- A diesel fuel-fired fire water pump engine;
- Natural gas piping and metering equipment; and
- Electrical equipment insulated with sulfur hexafluoride (SF_6).

A process flow diagram is included at the end of this section.

Pipeline natural gas is chosen as the only fuel for the combustion turbines and duct burner systems due to local availability of fuel and infrastructure to support delivery of the fuel to the facility in adequate volume and pressure.

2.2 COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS

The CTs will burn pipeline-quality natural gas to drive electrical generators. The main components of each CT turbine consist of a compressor, combustor, expansion turbine, and generator. The compressor pressurizes the inlet combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the expansion turbine where the gases expand as they pass through the power turbine sections, which generate torque that drives a shaft to power an electric generator. The temperature of the inlet air to the CTs for the proposed combined cycle project may occasionally be lowered using evaporative cooling to increase the mass air flow through the turbines and achieve maximum turbine power output on days with warm to hot ambient conditions.

The specific combustion turbine model being considered for the project is the GE 7HA.02, which has a base-load electric power output of approximately 328 MW at an ambient condition of 69.7 °F. The exhaust gases from each combustion turbine will be directed through their respective HRSG, supplemented with a set of natural gas-fired duct burners. The set of duct burners will have a maximum heat input capacity of approximately 770 MMBtu/hr higher heating value (HHV). The exhaust gases from the two HRSGs will be routed to the respective exhaust stacks (EPNs CTDB3-A and CTDB3-B).

Steam produced by each of the two HRSGs will be routed to a single steam turbine generator (STG), with a gross electric power output, accounting for DB firing, of approximately 501 MW at 69.7 °F. The two combustion turbines and one steam turbine will be coupled to electric generators to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid. Although the intended use of the proposed generating units is, primarily, to provide base-loaded power, the units may operate at reduced load to respond to changes in electrical grid power requirements and/or stability.

2.3 CT/HRSG MAINTENANCE, STARTUP AND SHUTDOWN ACTIVITIES

Planned maintenance, startup and shutdown (MSS) of the proposed combined cycle units (either or both of the two combustion turbines and their associated HRSGs) will be part of the routine operations at the facility. For startup of the GE combustion turbines, an optimized design will result in a reduction in the time required to ramp up each CT to a temperature where the DLN combustor and post-combustion control devices will be effective.

Startup and shutdown periods for the combustion turbines are defined by monitored operating conditions. For the combustion turbine, a startup period begins when an initial flame detection signal is recorded in the plant's Data Acquisition and Handling System (DAHS) and ends when the combustion turbine output reaches the unit's lowest sustainable load. The shutdown period begins when the gas turbine output drops below the unit's lowest sustainable load and ends when a flame detection signal is no longer recorded in the plant's DAHS.

Maintenance operations involving equipment and gas supply components of the combined cycle units could result in a limited release/venting of methane (CH_4) and carbon dioxide (CO_2) (in the natural gas) to the atmosphere (EPN MSS FUG).

2.4 DEW POINT HEATERS

Two 1.0 MMBtu/hr natural gas-fired dew point heaters (EPNs DP-HTRA and DP-HTRB) will be used as necessary to preheat the natural gas fuel. The natural gas will be preheated to prevent condensation from entering the combustion turbines. Although the heaters will only be operated when needed, 8,760 hours of operation have been conservatively used for the annual emissions calculations.

2.5 AUXILIARY BOILER

One auxiliary boiler (EPN AUX3) will be available to facilitate startup of the combined cycle units and maintain vacuum when the units are down. The auxiliary boiler will have a maximum heat input of 40 MMBtu/hr and will burn pipeline natural gas. The auxiliary boiler could operate up to 8,760 hours per year.

2.6 DIESEL-FIRED EMERGENCY EQUIPMENT

The site will be equipped with one nominally rated 2,937-bhp diesel-fired emergency generator (EPN EG3) to provide electricity to the facility in case of power failure. In addition, a nominally rated 250-bhp diesel-fired water pump (EPN FWP2) will be installed at the site to provide water in the event of a fire. Each emergency engine will be limited to 100 hours of non-emergency operation per year for purposes of maintenance checks and readiness testing.

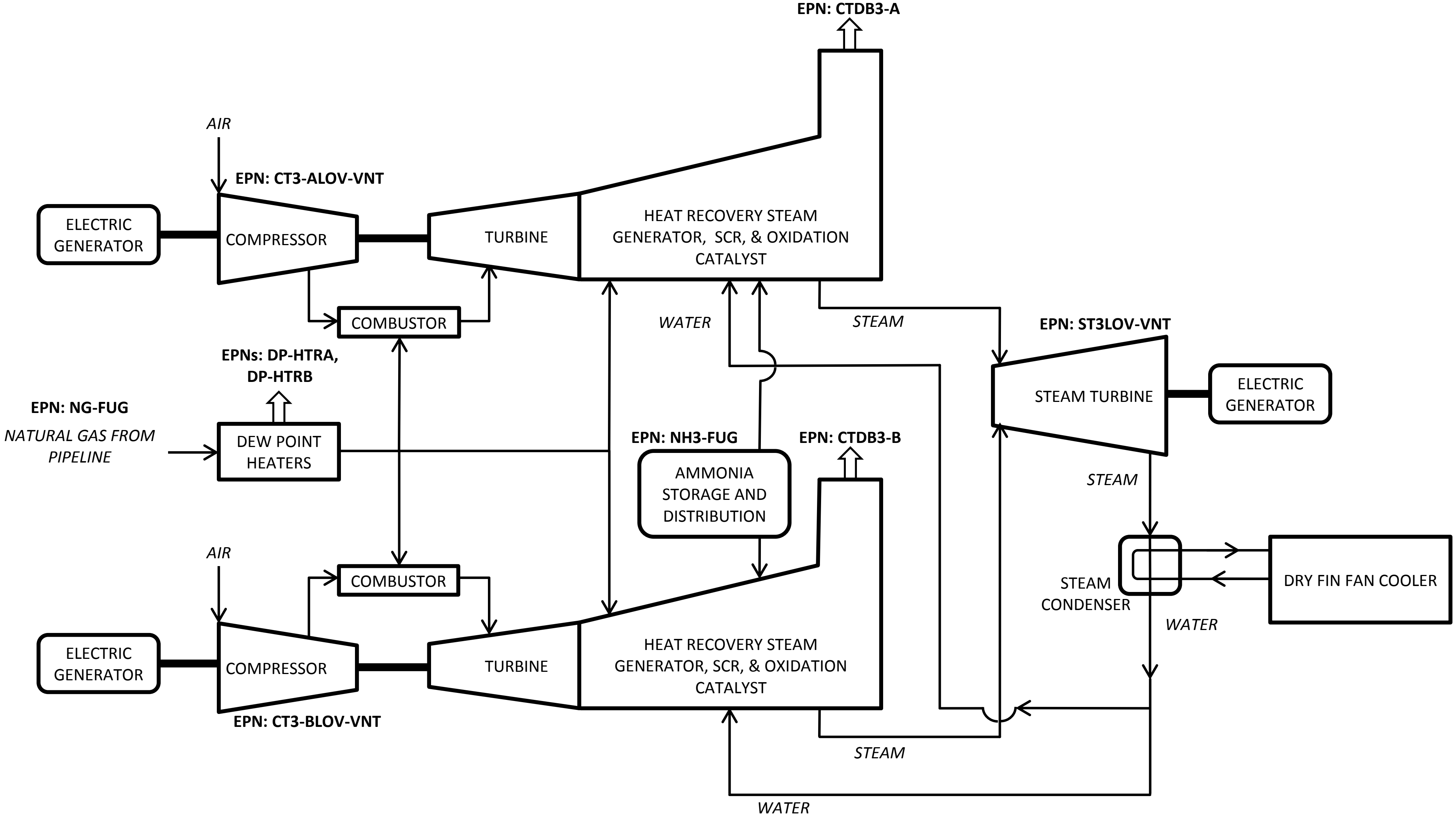
2.7 NATURAL GAS PIPING FUGITIVES

Natural gas is delivered to the site via pipeline. Gas will be metered and piped to the new combustion turbine and duct burners. Project fugitive emissions from the natural gas piping components associated with the new CT/HRSG units will include emissions CH_4 and CO_2. Fugitive emissions from the natural gas piping are designated as EPN NG-FUG.

2.8 ELECTRICAL EQUIPMENT INSULATED WITH SF_6

The generator circuit 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 equipment. SF_6 is only used in sealed and safe systems, which under normal circumstances do not leak gas. The total capacity of the circuit breakers associated with the proposed plant is estimated to be 1,160 lbs of SF_6. Fugitive emissions of SF_6 are designated as EPN SF6-FUG.

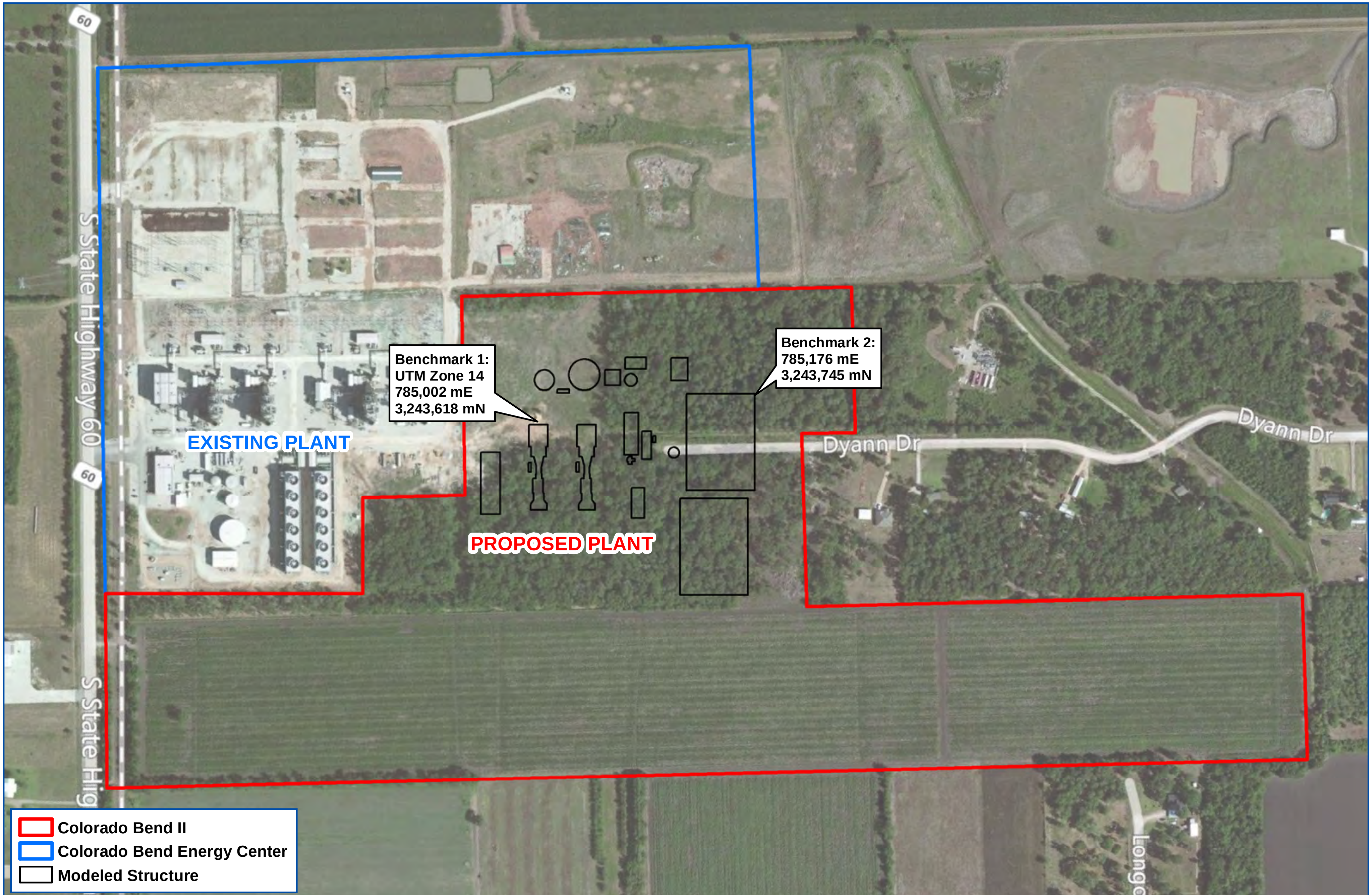
The proposed circuit breakers will have a low pressure alarm and a low pressure lockout. The alarm will alert operating personnel of any leakage in the system and the lockout prevents any operation of the breaker in the event there is a lack of "quenching and cooling" SF_6 gas.



OTHER MISCELLANEOUS EPNs:

EG3: Emergency Generator Unit 3
FWP2: Firewater Pump Unit 2
DSL-TK1: Diesel Tank 1
DSL-TK2: Diesel Tank 2
MSS FUG: Maintenance/Startup/Shutdown Fugitives
AUX3: Auxiliary Boiler 3

COLORADO BEND II			PROCESS FLOW DIAGRAM		
Permit Application			Filename: PFD 2014-09-11.xls		
zephyr	Drawn by: L Moon	Checked by: J Seinfeld	Project No.: 013492	Date: 9/11/2014	Sheet: 1 of 1



Map Sources: ESRI- BING Hybrid Basemap Datum: NAD 83 UTM Zone 14

0 150 300 Meters

0 500 1,000 Feet

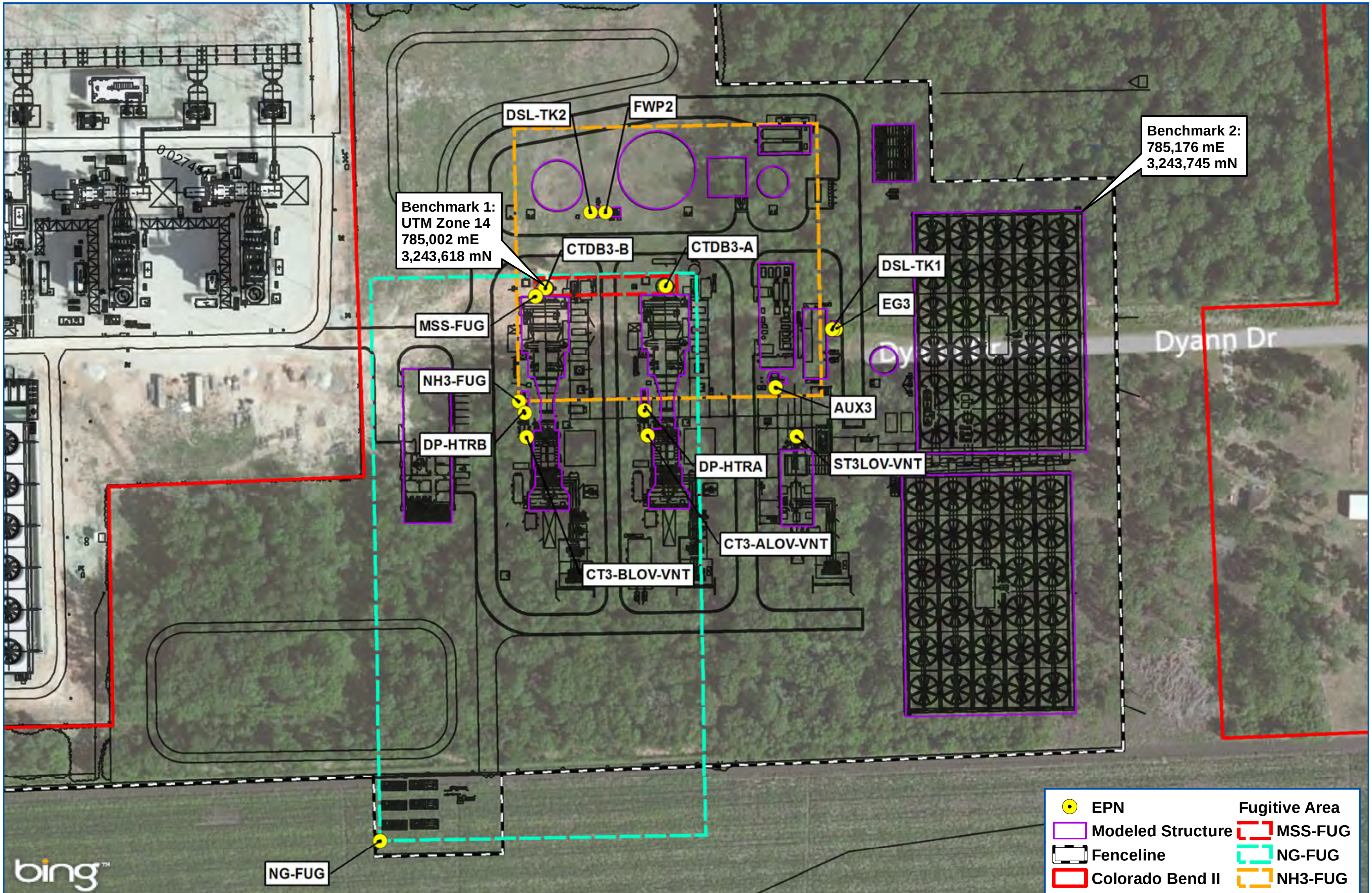
zephyr

PLOT PLAN - OVERVIEW

Colorado Bend II
Wharton County, Texas

H:\Exelon\013492 Colorado Bend\GIS\ArcMap\Plot Plan Overview - CO Bend.mxd

Drafted By:	Reviewed By:	Project No.:	Date:
J. Knowles	L. Moon	013492.001	9/11/2014



Map Sources: ESRI- BING Hybrid Basemap Datum: NAD 83 UTM Zone 14

0 150 300 Feet

0 50 100 Meters

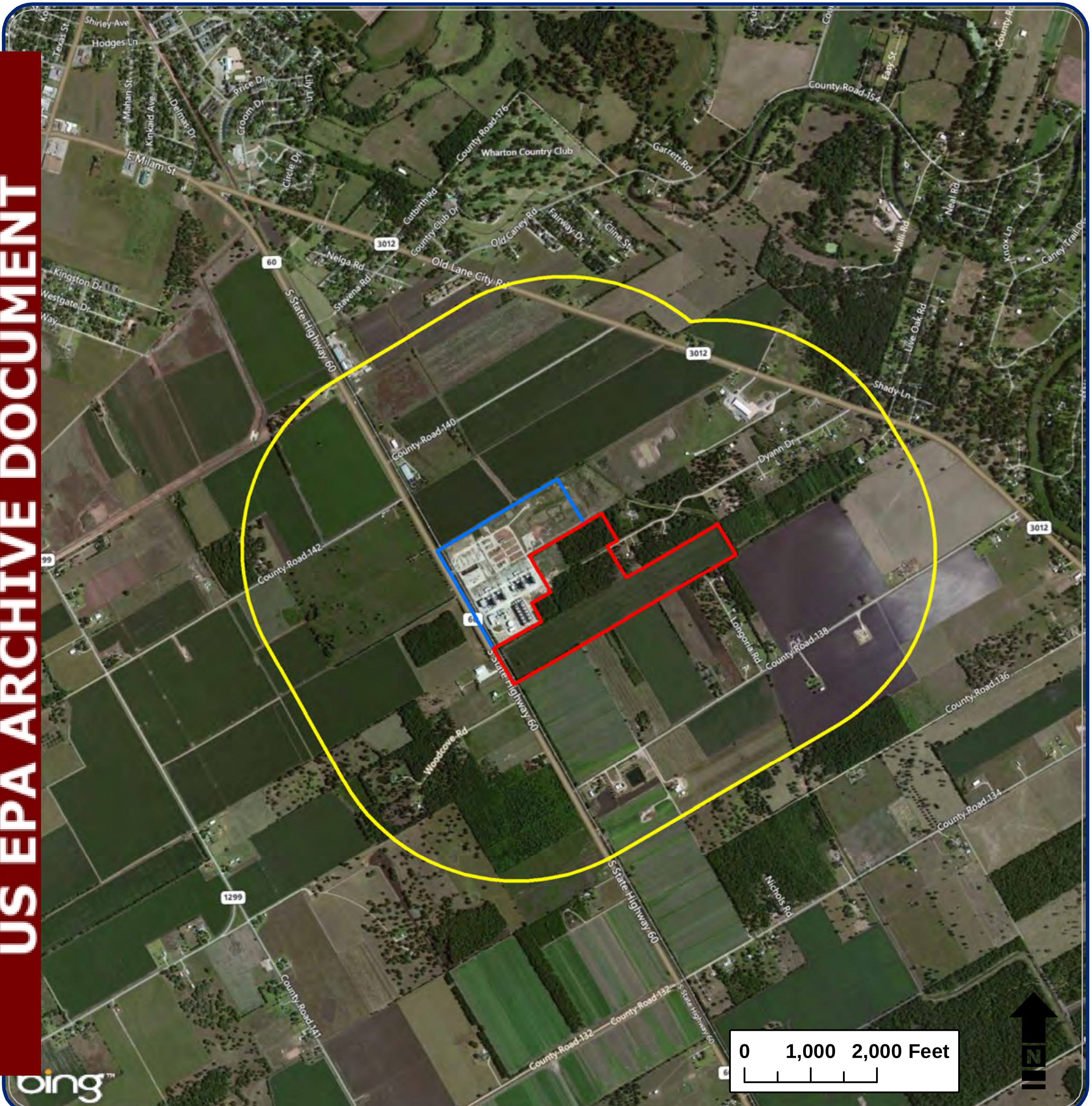
zephyr

PLOT PLAN - DETAIL

Colorado Bend II
Wharton County, Texas

H:\Exelon\013492 Colorado Bend\GIS\ArcMap\Plot Plan Detail - CO Bend.mxd

Drafted By:	Reviewed By:	Project No.:	Date:
J. Knowles	L. Moon	013492.001	9/11/2014



AREA MAP

Colorado Bend II

Colorado Bend II Power, LLC
Wharton County, Texas

zephyr

Colorado Bend II
Colorado Bend Energy Center
3000 Foot Radius

Data Sources:
ESRI- BING Hybrid &
Streets Basemaps
Datum: GCS WGS 1984
Date: 9/11/2014

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3.0 GHG EMISSION CALCULATIONS

3.1 GHG EMISSIONS FROM COMBINED CYCLE COMBUSTION TURBINES

GHG emissions from the combustion turbines and the HRSGs are calculated in accordance with the procedures in the Mandatory Greenhouse Reporting Rules, Subpart D – Electric Generation.[1] Annual CO_2 emissions are calculated using the methodology in equation G-4 of the Acid Rain Rules.[2]

$$W_{CO_2} = \left(\frac{F_C \times H \times U_f \times MW_{CO_2}}{2000} \right) \qquad (Eq.\ G\text{–}4)$$

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, 1,040 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.

Annual methane (CH_4) and nitrous oxide (N_2O) emissions are calculated using the emission factors (kg/MMBtu) for natural gas combustion from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[3] The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.

Calculations of base load GHG emissions from the combined cycle turbines are presented in Table 3-2.

3.2 AUXILIARY BOILER AND DEW POINT HEATERS

CO_2 emissions from the natural gas-fired auxiliary boiler and dew point heaters are calculated using the emission factors (kg/MMBtu) for natural gas from Table C-1 of the Mandatory Greenhouse Gas Reporting Rules.[4] CH_4 and N_2O emissions from the heater are calculated using the emission factors (kg/MMBtu) for natural gas from Table C-2 of the Mandatory Greenhouse

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[1] 40 C.F.R. 98, Subpart D – *Electricity Generation*
[2] 40 C.F.R. 75, Appendix G – *Determination of CO_2 Emissions*
[3] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-2
[4] *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-1

Gas Reporting Rules.[5] The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[6]

Calculations of GHG emissions from the dew point heaters and auxiliary boiler are presented in Table 3-3 and Table 3-8, respectively.

3.3 GHG EMISSIONS FROM NATURAL GAS PIPING FUGITIVES AND NATURAL GAS MAINTENANCE AND STARTUP/SHUTDOWN RELATED RELEASES

GHG emission calculations for natural gas/fuel gas piping component fugitive emissions are based on emission factors from Table W-1A of the Mandatory Greenhouse Gas Reporting Rules.[7]. The concentrations of CH_4 and CO_2 in the natural gas are based on a typical natural gas analysis. Since the CH_4 and CO_2 content of natural gas is variable, the concentrations of CH_4 and CO_2 from the typical natural gas analysis are used when determining the worst case mass emission rate estimate. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[8]

GHG emission calculations for releases of natural gas related to piping maintenance and turbine startup/shutdowns are calculated using the same CH_4 and CO_2 concentrations as natural gas/fuel gas piping fugitives.

Calculations of GHG emissions from natural gas piping fugitives are presented in Table 3-4. Calculations of GHG emissions from releases of natural gas related to piping maintenance and turbine maintenance and startup/shutdown activities is presented in Table 3-5.

3.4 GHG EMISSIONS FROM DIESEL-FIRED EMERGENCY ENGINES

CO_2 emissions from the diesel-fired emergency generator and fire pump engine are calculated using the emission factors (kg/MMBtu) for Distillate Fuel Oil No. 2 from Table C-1 of the Mandatory Greenhouse Gas Reporting Rules.[9] CH_4 and N_2O emissions from the diesel-fired engines are calculated using the emission factors (kg/MMBtu) for Petroleum from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[10] The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[11]

Calculations of GHG emissions from the emergency engines are presented in Table 3-6.

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[5] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-2
[6] *Global Warming Potentials*, 40 C.F.R. Pt. 98, Subpt. A, Tbl. A-1.
[7] Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production, 40 CFR 98, Subpart. W, Tbl. W-1A.
[8] *Global Warming Potentials*, 40 C.F.R. Pt. 98, Subpt. A, Tbl. A-1.
[9] *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-1
[10] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-2
[11] *Global Warming Potentials*, 40 C.F.R. Pt. 98, Subpt. A, Tbl. A-1.

3.5 GHG EMISSIONS FROM ELECTRICAL EQUIPMENT INSULATED WITH SF_6

SF_6 emissions from the SF_6 circuit breakers associated with the proposed units are calculated using a predicted SF_6 annual leak rate of 0.5% by weight. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[12]

Calculations of GHG emissions from electrical equipment insulated with SF_6 are presented in Table 3-7.

[12] *Global Warming Potentials*, 40 C.F.R. Pt. 98, Subpt. A, Tbl. A-1.

Table 3-1
Project GHG Emission Summary
Colorado Bend II

Name	EPN	GHG Mass Emissions (ton/yr)	CO_2e (ton/yr)
CT/HRSG Unit 1 (GE 7HA.02)	CTDB3-A	1,975,227	1,977,194
CT/HRSG Unit 2 (GE 7HA.02)	CTDB3-B	1,975,227	1,977,194
Dew Point Heater No. 1	DP-HTRA	512	513
Dew Point Heater No. 2	DP-HTRB	512	513
Natural Gas Fugitives	NG-FUG	21	476
Gas Venting	MSS FUG	0.11	3
Emergency Generator	EG3	155	156
Fire Water Pump	FWP2	16	16
SF_6 Insulated Equipment	SF6-FUG	0.003	66
Auxiliary Boiler	AUX3	20,495	20,515
Total Project Emissions:		**3,972,166**	**3,976,647**

Table 3-2

GHG Annual Emission Calculations - GE 7HA.02 Combined Cycle Combustion Turbines

Colorado Bend II

EPN	Average Heat Input[1] (MMBtu/hr)	Annual Heat Input[2] (MMBtu/yr)	Pollutant	Emission Factor (lb/MMBtu)[3]	GHG Mass Emissions[4] (tpy)	Global Warming Potential[5]	CO_2e (tpy)
CTDB3-A	3,794	33,236,316	CO_2	118.86	1,975,187	1	1,975,187
			CH_4	2.2E-03	36.6	25	915.9
			N_2O	2.2E-04	3.7	298	1,091.8
				Total:	**1,975,227**		**1,977,194**
CTDB3-B	3,794	33,236,316	CO_2	118.86	1,975,187	1	1,975,187
			CH_4	2.2E-03	36.6	25	915.9
			N_2O	2.2E-04	3.7	298	1,091.8
				Total:	**1,975,227**		**1,977,194**
				Total for 2 Turbines:	***3,950,454***		***3,954,389***

<u>Notes</u>

1. *The average heat input for the GE 7HA.02 unit is based on the HHV heat input at 100% load, with duct burner firing, at 69.7 ^oF ambient temperature.*
2. *Annual heat input based on 8,760 hours per year operation.*
3. *CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
4. *CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4*

$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2000$

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

F_c = Carbon based F-factor,1040 scf/MMBtu

H = Heat Input (MMBtu/yr)

U_f = 1/385 scf CO_2/lbmole at 14.7 psia and 68 ^oF

MW_{CO2} = Molecule weight of CO_2, 44.0 lb/lb-mole

5. *Global Warming Potential factors revised as part of amendments made to the Greenhouse Gas Reporting Rule (78 FR 71904).*

Table 3-3
GHG Annual Emission Calculations - Dew Point Heaters
Colorado Bend II

EPN	Maximum Heat Input[1] (MMBtu/yr)	Pollutant	Emission Factor (lb/MMBtu)[2]	GHG Mass Emissions (tpy)	Global Warming Potential[3]	CO_2e (tpy)
DP-HTRA	8,760	CO_2	116.98	512	1	512
		CH_4	2.2E-03	0.01	25	0.24
		N_2O	2.2E-04	0.001	298	0.29
			Total:	**512**		**513**
DP-HTRB	8,760	CO_2	116.98	512	1	512
		CH_4	2.2E-03	0.01	25	0.24
		N_2O	2.2E-04	0.001	298	0.29
			Total:	**512**		**513**

Notes
1. *Based on project design for two 1.0-MMBtu/hr dew point heaters, each operating 8,760 hours per year.*
2. *CO_2, CH_4, and N_2O factors based on Tables C-1 and C-2 of 40 CFR Part 98, Mandatory Greenhouse Gas Reporting.*
3. *Global Warming Potential factors revised as part of amendments made to the Greenhouse Gas Reporting Rule (78 FR 71904).*

Table 3-4
GHG Annual Emission Calculations - Natural Gas Piping Fugitives
Colorado Bend II

GHG Emissions Contribution From Fugitive Natural Gas Piping Components

EPN	Source Type	Fluid State	Count	Emission Factor[1] (scf/hr/comp)	CO_2[2] (tpy)	CH_4[3] (tpy)	**Total (tpy)**
NG-FUG	Valves	Gas/Vapor	600	0.121	1.090	12.016	
	Flanges	Gas/Vapor	2,400	0.017	0.613	6.753	
	Relief Valves	Gas/Vapor	5	0.193	0.014	0.160	
	Open-Ended Lines	Gas/Vapor	10	0.031	0.0047	0.0513	
	Compressors	Gas/Vapor	3	0.003	0.000135	0.00149	
GHG Mass-Based Emissions					1.722	18.98	**20.70**
Global Warming Potential[4]					1	25	
CO_2e Emissions					1.722	474.53	**476.26**

Notes

1. *Emission factors from Table W-1A of 40 CFR 98 Mandatory Greenhouse Gas Reporting published in the May 21, 2012 Technical Corrections*
2. *CO_2 emissions based on vol% of CO_2 in natural gas* 3.00%
3. *CH_4 emissions based on vol% of CH_4 in natural gas* 90.70%
4. *Global Warming Potential factor for CH_4 revised as part of amendments made to the Greenhouse Gas Reporting Rule (78 FR 71904).*

Example calculation:

600 valves	0.121 scf gas	0.03 scf CO2	lbmole	44 lb CO_2	8760 hr	ton =	1.09 ton/yr
	hr * valve	scf gas	385 scf	lbmole	yr	2000 lb	

TABLE 3-5
Gaseous Fuel Venting During Turbine Shutdown/Maintenance and Small Equipment and Fugitive Component Repair/Replacement
Colorado Bend II

EPN	Source Type	Initial Conditions			Final Conditions			Annual Emissions		**Total (tpy)**
		Volume[1] (ft^3)	Press. (psig)	Temp. (°F)	Press. (psig)	Temp. (°F)	Volume[2] (scf)	CO_2[3] (tpy)	CH_4[4] (tpy)	
MSS FUG	Turbine Fuel Line Shutdown/Maintenance	1,146	50	50	0	68	5,277	0.0090	0.10	
	Small Equipment/Fugitive Component Repair/Replacement	6.7	50	50	0	68	31	0.00005	0.00058	
GHG Mass-Based Emissions								0.0091	0.1000	**0.11**
Global Warming Potential[5]								1	25	
CO_2e Emissions								0.0091	2.5	**2.5**

Notes

1. Initial volume is calculated by multpilying the crossectional area by the length of pipe using the following formula: V_i = pi * [(diameter in inches/12)/2]^2 * length in feet = ft^3
2. Final volume calculated using ideal gas law $[(PV/ZT)_i = (PV/ZT)_f]$. $V_f = V_i (P_i/P_f) (T_f/T_i) (Z_f/Z_i)$, where Z is estimated using the following equation: $Z = 0.9994 - 0.0002P + 3E\text{-}08P^2$.
3. *CO_2 emissions based on vol% of CO_2 in natural gas* — 3.00% — from natural gas analysis
4. *CH_4 emissions based on vol% of CH_4 in natural gas* — 90.7% — from natural gas analysis
5. *Global Warming Potential factor for CH_4 revised as part of amendments made to the Greenhouse Gas Reporting Rule (78 FR 71904).*

Example calculation:

5277 scf Nat Gas	0.03 scf CO2	lbmole	44 lb CO_2	ton =	=	0.0090	ton/yr CO_2
yr	scf Nat Gas	385 scf	lbmole	2000 lb			

Table 3-6
GHG Annual Emission Calculations - Emergency Engines
Colorado Bend II

GHG Emissions Contribution From Combustion In Diesel Engines

Assumptions:

	Emergency Generator	**Fire Water Pump**	
Annual Operating Schedule:	100	100	hours/year
Power Rating:	2,937	250	bhp
Max Hourly Fuel Use:	138.0	14.6	gal/hr
Heating Value of No. 2 Fuel Oil[1]:	0.138	0.138	MMBtu/gal
Max Hourly Heat Input:	19.0	2.0	MMBtu/hr
Annual Heat Input:	1,904.4	201.5	MMBtu/yr

EPN	Heat Input (MMBtu/yr)	Pollutant	Emission Factor (lb/MMBtu)[2]	GHG Mass Emissions (tpy)	Global Warming Potential[3]	CO_2e (tpy)
EG3	1,904.4	CO_2	163.05	155.3	1	155.3
		CH_4	6.6E-03	0.0063	25	0.16
		N_2O	1.3E-03	0.0013	298	0.38
			Total:	**155.27**		**155.79**

FWP2	201.5	CO_2	163.05	16.4	1	16.4
		CH_4	6.6E-03	0.0007	25	0.02
		N_2O	1.3E-03	0.0001	298	0.04
			Total:	**16.43**		**16.48**

Calculation Procedure

Annual Emission Rate = annual heat Input X Emission Factor X 2.2 lbs/kg X Global Warming Potential / 2,000 lbs/ton

Notes

1. *Default high heat value based on Table C-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
2. *CO_2, CH_4, and N_2O factors based on Tables C-1 and C-2 of 40 CFR Part 98, Mandatory Greenhouse Gas Reporting.*
3. *Global Warming Potential factors revised as part of amendments made to the Greenhouse Gas Reporting Rule (78 FR 71904).*

Table 3-7

GHG Annual Emission Calculations - Electrical Equipment Insulated With SF_6

Colorado Bend II

Assumptions

Insulated circuit breakers SF_6 capacity:	1,160	lb
Estimated annual SF_6 leak rate:	0.5%	by weight
Estimated annual SF_6 mass emission rate:	0.0029	ton/yr
Global Warming Potential[1]:	22,800	
Estimated annual CO_2e emission rate:	66.1	ton/yr

Notes

Global Warming Potential factor for SF_6 revised as part of amendments made to the Greenhouse Gas Reporting Rule (78 FR 71904).

Table 3-8
GHG Annual Emission Calculations - Auxiliary Boiler
Colorado Bend II

EPN	Maximum Heat Input[1] (MMBtu/yr)	Pollutant	Emission Factor (lb/MMBtu)[2]	GHG Mass Emissions (tpy)	Global Warming Potential[3]	CO_2e (tpy)
AUX3	350,400	CO_2	116.98	20,494	1	20,494
		CH_4	2.2E-03	0.39	25	9.7
		N_2O	2.2E-04	0.039	298	11.5
			Total:	**20,495**		**20,515**

<u>Notes</u>

1. *Based on design heat input for a 40-MMBtu/hr auxiliary boiler operating 8,760 hours per year.*
2. *CO_2, CH_4, and N_2O factors based on Tables C-1 and C-2 of 40 CFR Part 98, Mandatory Greenhouse Gas Reporting.*
3. *Global Warming Potential factors revised as part of amendments made to the Greenhouse Gas Reporting Rule (78 FR 71904).*

4.0 PREVENTION OF SIGNIFICANT DETERIORATION APPLICABILITY

The proposed project will be a major modification under 40 CFR §52.21; thus, PSD review is required for all PSD-regulated contaminants for which there will be a significant emissions increase. Because PSD requirements are triggered for this project for non-GHG pollutants and the GHG emissions increase associated with the proposed project will be greater than 75,000 ton/yr of CO_2e, a PSD BACT review is triggered for GHG emissions in accordance with the EPA memo entitled "Next Steps and Preliminary Views on the Application of Clean Air Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in Utility Air Regulatory Group v. Environmental Protection Agency," dated July 24, 2014.

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TCEQ

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.:	TBD	Application Submittal Date:	09/11/2014
Company	Colorado Bend II Power, LLC		
RN:	TBD	Facility Location:	3863 S State Highway 60
City	Wharton	County:	Wharton
Permit Unit I.D.:	CTDB3-A & CTDB3-B	Permit Name:	TBD
Permit Activity:	☐ New Major Source	☑ Modification	
Project or Process Description:	Construction of a combined cycle electric generating plant		

Complete for all pollutants with a project emission increase.	POLLUTANTS						
	Ozone		CO	SO_2	PM	GHG	CO_2e
	NOx	VOC					
Nonattainment? (yes or no)						No	No
Existing site PTE (tpy)	This form for GHG only					2,210,363	2,212,566
Proposed project increases (tpy from 2F)[3]						3,972,166	3,976,647
Is the existing site a major source? If not, is the project a major source by itself? (yes or no)						Yes	Yes
If site is major, is project increase significant? (yes or no)						Yes	Yes
If netting required, estimated start of construction:		9/11/15					
5 years prior to start of construction:		9/11/10	Contemporaneous				
estimated start of operation:		9/11/17	Period				
Net contemporaneous change, including proposed project, from Table 3F (tpy)						3,972,166	3,976,647
FNSR applicable? (yes or no)						Yes	Yes

1. Other PSD pollutants
2. Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR §51.166(b)(1).
3. Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR §51.166(b)(23).
4. Since there are no contemporaneous decreases which would potentially affect PSD applicability and an impacts analysis is not required for GHG emissions, contemporaneous emission changes are not included on this table.

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	GHG			**Permit:**
Baseline Period:	N/A	**to**	N/A	

				A	B				
Affected or Modified Facilities[2]			**Permit No.**	**Actual Emissions[3]**	**Baseline Emissions[4]**	**Proposed Emissions[5]**	**Projected Actual Emissions**	**Difference (B - A)[6]**	**Correction[7]**	**Project Increase[8]**

	FIN	**EPN**	**Permit No.**	**Actual Emissions[3]**	**A: Baseline Emissions[4]**	**B: Proposed Emissions[5]**	**Projected Actual Emissions**	**Difference (B - A)[6]**	**Correction[7]**	**Project Increase[8]**
1	CTDB3-A	CTDB3-A			0.00	1,975,227		1,975,227		1,975,227
2	CTDB3-B	CTDB3-B			0.00	1,975,227		1,975,227		1,975,227
3	DP-HTRA	DP-HTRA			0.00	512		512		512
4	DP-HTRB	DP-HTRB			0.00	512		512		512
5	NG-FUG	NG-FUG			0.00	21		21		21
6	MSS FUG	MSS FUG			0.00	0.11		0		0
7	EG3	EG3			0.00	155		155		155
8	FWP2	FWP2			0.00	16		16		16
9	SF6-FUG	SF6-FUG			0.00	0.0029		0.0029		0.0029
10	AUX3	AUX3			0.00	20,495		20,495		20,495
11										
12										
13										
14										
							Page Subtotal[9]			3,972,166

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	CO_2e	**Permit:**	
Baseline Period:	N/A	**to**	N/A

Affected or Modified Facilities[2]	FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions[5]	Projected Actual Emissions	Difference (B - A)[6]	Correction[7]	Project Increase[8]
1	CTDB3-A	CTDB3-A			0.00	1,977,194		1,977,194		1,977,194
2	CTDB3-B	CTDB3-B			0.00	1,977,194		1,977,194		1,977,194
3	DP-HTRA	DP-HTRA			0.00	513		513		513
4	DP-HTRB	DP-HTRB			0.00	513		513		513
5	NG-FUG	NG-FUG			0.00	476		476		476
6	MSS FUG	MSS FUG			0.00	3		3		3
7	EG3	EG3			0.00	156		156		156
8	FWP2	FWP2			0.00	16		16		16
9	SF6-FUG	SF6-FUG			0.00	66		66		66
10	AUX3	AUX3			0.00	20,515		20,515		20,515
11										
12										
13										
14										
							Page Subtotal[9]			3,976,647

All emissions must be listed in tons per year (tpy). The same baseline period must apply for all facilities for a given NSR pollutant.

1. Individual Table 2F's 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) 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.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

EPA's PSD rules define BACT as follows:

> *Best available control technology* means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.[13]

In the EPA guidance document titled *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA recommends the use of the Agency's five-step "top-down" BACT process to determine BACT for GHGs.[14] 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.

EPA has broken down this analytical process into the following five steps:

- Step 1: Identify all available control technologies
- Step 2: Eliminate technically infeasible options
- Step 3: Rank remaining control technologies
- Step 4: Evaluate most effective controls and document results
- Step 5: Select the BACT.

[13] 40 C.F.R. § 52.21(b)(12.)
[14] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, p. 18 (Nov. 2010).

5.1 BACT FOR THE COMBINED-CYCLE COMBUSTION TURBINES

5.1.1 Step 1: Identify All Available Control Technologies

5.1.1.1 Inherently Lower-Emitting Processes/Practices/Designs

A summary of available, lower greenhouse gas emitting processes, practices, and designs for combustion turbine power generators is presented below.

5.1.1.1.1 Combustion Turbine Energy Efficiency Processes, Practices, and Designs

Combustion Turbine Design

CO_2 is a product of combustion of fuel containing carbon, which is inherent in any power generation technology using fossil fuel. It is not possible to reduce the amount of CO_2 generated from 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, there is no technology available that can effectively reduce CO_2 generation by adjusting the conditions in which combustion takes place.

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.

The most efficient way to generate electricity from a natural gas fuel source is the use of a combined cycle design. For fossil fuel technologies, efficiency ranges from approximately 30-50% (higher heating value [HHV]). A typical coal-fired Rankine cycle power plant has a base load efficiency of approximately 30% (HHV), while a modern H-Class natural gas-fired combined cycle unit operating under optimal conditions has a base load 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.

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

Periodic Burner Tuning

Modern H-Class combustion turbines have regularly scheduled routine 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 efficiency to the combustion turbines.

Reduction in Heat Loss
Modern H-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 H-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, to achieve efficient low-NO_X combustion. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal performance for full-load and part-load conditions, thereby minimizing emissions of greenhouse gases.

5.1.1.1.2 Heat Recovery Steam Generator Energy Efficiency 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. The duct burner firing provides additional power generation capacity during periods of high electrical demand.

The modern large 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
HRSGs 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 employ recirculation systems to minimize cold-end corrosion, and stack dampers are used for cycling operation to conserve the thermal energy within the HRSG when the unit is off line.

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 modern large 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 surrounding air, 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. Additionally, power plant operators are concerned with overall efficiency of their facilities. Therefore, steam leaks are repaired as soon as possible to maintain facility performance. Minimization of vented steam and repair of steam leaks will be performed for this project.

5.1.1.1.3 Steam Turbine Energy Efficiency Processes, Practices, and Designs

The steam turbine for this project will be a modern, high-efficiency, reheat, condensing unit. Steam turbines have been in operation for over a century, and are generally classified as impulse or reaction. However, most modern turbines employ both impulse and reaction blading. The overall efficiency of the unit is affected by a number of items, including the inlet steam conditions, the exhaust steam conditions, the blading design, the turbine seals, and the generator efficiency.

Use of Reheat Cycles
The efficiency of a steam turbine is directly related to the steam conditions entering the turbine. The higher the steam temperature and pressure, the higher the overall efficiency. To achieve the higher temperatures, reheat cycles are employed. This is necessary to minimize the condensed moisture content of the exhaust steam exiting a turbine stage. If the moisture content of the exhaust steam is too high, erosion of the last-stage turbine blades occurs. A typical reheat cycle reheats partially expanded steam from the steam turbine. For a modern combined cycle facility, the high-pressure inlet and intermediate-pressure inlet steam temperatures typically are 1,050°F and above, and the high-pressure steam turbine inlet pressure is typically in the range of 1,800-2,400 psig.

Use of Exhaust Steam Condenser
Steam turbine efficiency is also improved by lowering the exhaust steam conditions of the unit. The lower the exhaust pressure, the higher the overall turbine efficiency. For high-efficiency units, the exhaust steam is saturated under vacuum conditions. This is accomplished by the use of a condenser. The condensing steam creates a vacuum in the condenser, which increases steam turbine efficiency.

Efficient Blading Design
Blading design also affects the overall efficiency of the turbine. As noted earlier, steam turbines have been used to generate power for over a century, and are either impulse or reaction design. The blade design has evolved for high-efficiency transfer of the energy in the steam to power generation. Additionally, 3-D computer-aided design technology is also employed to provide the highest efficiency blade design. Blade materials are also important components in blade design, which allow for high-temperature and large exhaust areas to improve performance.

Turbine seals are also important in the overall performance of the steam turbine. The high-pressure steam will leak to the atmosphere along the turbine shaft, as well as bypass the turbine stages if sealing is not employed. The steam turbine designers have multiple steam seal designs to obtain the highest efficiency from the steam turbine.

Efficient Steam Turbine Generator Design
The steam turbine generator is also a key element in the overall performance of the steam turbine. The modern generator is a high-efficiency unit. The generator for modern steam turbines is typically cooled by one of three methods. These methods are open-air cooling, totally enclosed water-to-air cooling, or hydrogen cooling. These cooling methods allow for the highest efficiency of the generator, resulting in an overall high-efficiency steam turbine. According to combustion

turbine manufacturer representatives, there is no energy penalty between the three cooling methods. The cooling method for the proposed Colorado Bend II steam turbine will be open-air cooling.

5.1.1.1.4 Additional Energy Efficiency 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 temperature.
- *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 a train operating at less efficient part-load conditions and ramping up the remaining train 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 at part-load, improving the facility's overall efficiency.

5.1.1.2 Add-On Controls

In addition to power generation process technology options discussed above, it is appropriate to consider whether add-on technologies are possible ways to capture GHG emissions that are emitted from natural gas combustion in the proposed project's CT/HRSG units 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 geologic 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:

> "Post-combustion CO_2 capture is primarily applicable to conventional natural gas and pulverized coal-fired (PC) power generation. In a typical PC power plant, fuel is burned with air in a boiler to produce steam, which drives a turbine to generate electricity. The boiler exhaust, or flue gas, consists mostly of nitrogen (N_2) and CO_2."[15]

The DOE-NETL adds:

> "…Separating CO_2 from 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 (slightly above atmospheric); thus, a large volume of gas has to 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.
> - CO_2 is captured at low pressure. Compressing it from atmospheric to pipeline pressure (about 2,000 psia) will incur a large auxiliary power load on the overall power plant system…"[16]

For the GE combustion turbine being considered for this project, the CO_2 stack concentration at base load is approximately 4.1 vol% without duct burner firing and 5.1 vol% with duct burner firing.

If CO_2 capture can be achieved at a power plant, it would need to be routed to a geologic formation capable of long-term storage. The long-term storage potential for a formation is a function of the volumetric capacity of a geologic 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 geologic formations that could potentially serve as CO_2 storage sites as follows:

> "Geologic carbon dioxide (CO_2) storage involves the injection of supercritical CO_2 into deep geologic formations (injection zones) overlain by competent sealing formations and geologic 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 geologic 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 geologic storage would be anticipated to flow in the future. The different storage formation classes include: deltaic, coal/shale, fluvial, alluvial,

[15] DOE-NETL, *CO_2 Capture Information Portal,* http://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/capture-approaches
[16] *Id.*

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…"[17]

5.1.2 Step 2: Eliminate Technically Infeasible Options

Amine absorption technology for CO_2 capture has been applied to processes in the petroleum refining and natural gas processing industries, so it has been argued that it is technically feasible to apply that technology to exhausts for power plants. However, that technology has not been commercially available to power plants gas turbine exhausts, which have considerably larger flow volumes and considerably lower CO_2 concentrations. The high energy demand, high water demand, technical difficulties and economic costs associated with CCS are addressed in Step 4 of this section.

5.1.3 Step 3: Rank Remaining Control Technologies

As documented in Step 4 below, all of the energy efficiency related processes, practices, and designs discussed in Section 5.1.1.1 of this application are being proposed for this project, a ranking of the control technologies is not necessary for this application.

5.1.4 Step 4: Evaluate Most Effective Controls and Document Results

As all of the energy efficiency related processes, practices, and designs discussed in Section 5.1.1.1 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.

In this section, Colorado Bend II Power addresses the potential energy, environmental, and economic feasibility of implementing CCS technology as BACT for GHG emissions from the proposed project's gas turbine/HRSG trains. Each component of CCS technology (i.e., capture and compression, transport, and storage) is discussed separately.

5.1.4.1 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 more difficult to apply to 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:

[17] DOE-NETL, *Carbon Sequestration: Geologic Storage Focus Area,* http://www.netl.doe.gov/technologies/carbon_seq/corerd/storage.html

> "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."[18]

In its current CCS research program plans, the DOE-NETL confirms that commercial CO_2 capture technology for large-scale power plants is not yet available and suggests that it may not be available until at least 2020:

> "The overall objective of the Carbon Sequestration Program is to develop and advance CCS technologies that will be ready for widespread commercial deployment by 2020. To accomplish widespread deployment, four program goals have been established:
>
> (1) Develop technologies that can separate, capture, transport, and store CO_2 using either direct or indirect systems that result in a less than 10 percent increase in the cost of energy by 2015;
>
> (2) Develop technologies that will support industries' ability to predict CO_2 storage capacity in geologic formations to within ±30 percent by 2015;
>
> (3) Develop technologies to demonstrate that 99 percent of injected CO_2 remains in the injection zones by 2015;
>
> (4) Complete Best Practices Manuals (BPMs) for site selection, characterization, site operations, and closure practices by 2020. Only by accomplishing these goals will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020 and through the next several decades."[19A]

Alstom is one of the major developers of commercial CO_2 capture technology using post-combustion amine absorption, post-combustion chilled ammonia absorption, and oxy-combustion. Alstom stated on its website in early 2012 that its CO_2 capture technology would not become commercially available until approximately 2015.[20] Furthermore, it should be noted that, in committing to this timeframe, the company does not indicate whether such technology will be able to handle the volume of CO_2 emissions generated by a project of the size of the proposed Colorado Bend II project.

Another challenge of CO_2 capture is conservation of water resources. A modern natural gas-fired combined cycle facility typically requires four to five million gallons of water per day for condenser cooling and boiler make-up service. This amount will vary based on ambient temperature and humidity as well as the level of duct firing in the HRSG. Adding CO_2 separation facilities and

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[18] *Report of the Interagency Task Force on Carbon Capture and Storage* at 50 (Aug. 2010).
[19] DOE-NETL, *Carbon Sequestration Program: Technical Program Plan,* at 10 (Feb. 2011).
[20] Alstom, *Alstom's Carbon Capture Technology Commercially "Ready to Go" by 2015*, Nov. 30, 2010, http://www.alstom.com/australia/news-and-events/pr/ccs2015/ (last visited Sept. 28, 2011).

compression equipment would significantly increase the cooling water requirements of a generating station. Studies have indicated that employing CCS on a natural gas-fired combined cycle facility could increase water consumption by more than 90%. In the case of Colorado Bend II, which relies on an air-cooled condenser design (i.e., "dry cooling"), the use of this amount of water conflicts with the water conservation-based design of the project.

5.1.4.2 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. Potential geologic storage sites in Texas, Louisiana, and Mississippi to which CO_2 could be transported (if a supporting pipeline were to be constructed) are delineated on the map found at the end of Section 5.[21] 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 large-scale, long-term CO_2 storage. The hypothetical minimum length required for any such pipeline(s) is the distance to the closest site with recognized potential for some geological storage of CO_2. One such site is an Enhanced Oil Recovery (EOR) candidate reservoir site located approximately 10 miles south of the project site. However, none of the eastern Texas EOR reservoir or other geologic formation sites have been technically demonstrated for large-scale, long-term CO_2 storage.

In comparison, the closest site that has been field-tested to demonstrate its capacity for large-scale geological storage of CO_2 is the Frio Brine Sequestration Field Test site ("Frio test site"), located east of Houston, Texas, almost 100 miles northeast of the proposed project site (see the map at the end of Section 5 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 long and sizable pipeline would need to be constructed to transport the large volume of high-pressure CO_2 from Colorado Bend II to the storage facility, thereby rendering implementation of a CO_2 transport system infeasible due to the complexities and cost of doing so.

5.1.4.3 CO_2 Storage

Even if it is assumed that 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

[21] Susan Hovorka, University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, *New Developments: Solved and Unsolved Questions Regarding Geologic Sequestration of CO_2 as a Greenhouse Gas Reduction Method* (GCCC Digital Publication #08-13) at slide 4 (Apr. 2008), available at: http://www.beg.utexas.edu/gccc/forum/codexdownloadpdf.php?ID=100(last visited Feb. 27, 2012).

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;[22] and
- Potential effects on wildlife.

Potentially suitable storage sites, including EOR sites and saline formations, exist in Texas, Louisiana, and Mississippi. In fact, one site with recognized potential for some geological storage of CO_2 is located approximately 10 miles from the proposed project; however, such sites have not yet been technically demonstrated with respect to all of the suitability factors described above. In comparison, the closest site that is 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 is the aforementioned Frio test site, located almost 100 miles northeast of the project site. It should be noted that, based on the suitability factors described above, currently the suitability of the Frio test 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.

Based on the reasons provided above, Colorado Bend II Power believes that CCS technology should be eliminated from further consideration as a potential feasible control technology for purposes of this BACT analysis. However, to answer possible questions that the public or the EPA may have concerning the relative costs of implementing hypothetical CCS systems, Colorado Bend II Power has estimated such costs. Construction of a carbon capture system at the Colorado Bend II site would require installation of the following major pieces of equipment:

- Two amine scrubber vessels;
- Two CO_2 strippers;
- Four amine transfer pumps;
- Four flue gas fans;
- Four CO_2 gas compressors; and
- One amine storage tank.

The estimated costs associated with implementation of a carbon capture system for the proposed project are shown in the table below. A control cost for implementing CCS in terms of \$/ton of CO_2 sequestered was calculated using the “cost of electricity” methodology outlined in the U.S.

[22] *Id.*

Department of Energy document "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity", Revision 2a, September 2013, DOE/NETL-2010/1397. Most of the inputs into this table were the default values from the DOE/NETL document except for the distance to the CCS storage site. This distance was increased from 100 km to 160 km (based on the distance between Colorado Bend II and the Frio test site). The calculated costs for CCS were still very comparable to the DOE/NETL results.

Carbon Capture and Sequestration Cost Summary

	Two Combustion Turbines and One Steam Turbine Without CCS	Two Combustion Turbines and One Steam Turbine With CCS
Cost-of-Electricity (COE) ($/MWh) @ 85% capacity factor	51.53 $/MWh	86.70 $/MWh
CO_2 Emissions	3,971,892 tons/yr[1]	397,189 tons/yr[2]
Cost of CO_2 Avoided		$83.40/ton CO_2

[1]Includes CO_2 emissions from heaters (2) and auxiliary boiler
[2]Based on DOE-NETL assumed removal efficiency of 90% for carbon capture system

In addition to the high construction and operating costs associated with CCS, the carbon capture equipment requires a substantial amount of energy to operate, thereby reducing the net electrical output of the plant. Operation of carbon capture equipment at a typical natural gas-fired combined cycle plant is estimated to reduce the net energy efficiency (HHV basis) of the plant from approximately 51.0% to approximately 43.5%.[23]

Furthermore, the additional costs associated with CCS would be expected to result in reduced annual utilization in the competitive Texas power market relative to a combined cycle plant without CCS. Therefore, the cost per ton removed would be expected to exceed that shown in the table above approximately in proportion to the reduced utilization.

5.1.5 Step 5: Select BACT

Colorado Bend II Power proposes the following energy efficiency processes, practices, and designs as BACT for the proposed combined cycle combustion turbines:

- Use of Combined Cycle Power Generation Technology;
- Combustion Turbine Energy Efficiency Processes, Practices, and Designs:
    - Efficient turbine design,
    - Turbine inlet air cooling,
    - Periodic turbine burner tuning,
    - Reduction in heat loss, and

[23] US Department of Energy, National Energy Technology Laboratory, "Cost and Performance Baseline For Fossil Energy Plants, Volume 1 - Bituminous Coal and Natural Gas to Electricity", Revision 2a, September 2013.

    - Instrumentation and controls;
- HRSG Energy Efficiency Processes, Practices, and Designs:
    - Efficient heat exchanger design,
    - Insulation of HRSG,
    - Minimizing Fouling of heat exchange surfaces, and
    - Minimizing vented steam and repair of steam leaks;
- Steam Turbine Energy Efficiency Processes, Practices, and Designs:
    - Use of Reheat Cycles,
    - Use of Exhaust Steam Condenser,
    - Efficient Blading Design, and
    - Efficient Generator Design;
- Additional Energy Efficiency Processes, Practices, and Designs:
    - Fuel gas preheating,
    - Drain operation,
    - Multiple combustion turbine/HRSG trains, and
    - Boiler feed pump fluid drive design.

To determine the appropriate heat-input efficiency limit, Colorado Bend II Power started with the turbine's design base load gross heat rate for combined cycle operation and then calculated a compliance margin based upon reasonable degradation factors that may foreseeably reduce efficiency under real-world conditions. The design base load gross heat rate for the proposed power plant, based on the GE combustion turbine being considered for this project, is 6,248 Btu/kWh (HHV) without duct burner firing and 6,557 Btu/kWh (HHV) with duct burner firing.

To determine an appropriate heat rate limit for the permit, the following compliance margins are added to the base heat rate limit:

- A 3.3% design margin reflecting the possibility that the constructed facility will not be able to achieve the design heat rate;
- A 6% degradation margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls; and
- A 3% performance margin reflecting the variability in operation of auxiliary plant equipment due to use over time.

Design and construction of a combined-cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, which are often imprecise or not reflective of conditions once installed at the site. As a consequence, the facility also calculates an "Installed Base Heat Rate", which represents a design margin of 3.3% to address such items as equipment underperformance and short-term degradation.

To establish an enforceable BACT condition that can be achieved over the life of the facility, the permit limit must also account for anticipated degradation of the equipment over time between regular maintenance cycles. The manufacturer's degradation curves project anticipated degradation rate of 5% within the first 48,000 hours of the gas turbine's useful life; they do not reflect any potential increase in this rate which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, the projected 5% degradation rate represents the average, and not the maximum or guaranteed, rate of degradation for the gas turbines. Therefore, Colorado Bend II Power proposes that, for purposes of deriving an enforceable BACT limitation on the proposed facility's heat rate, gas turbine degradation may reasonably be estimated at 6% of the facility's heat rate.

Finally, in addition to the heat rate degradation from normal wear and tear on the combustion turbines, Colorado Bend II Power is also providing a reasonable performance margin of 3% based on potential degradation in other elements of the combined cycle plant that would cause the overall plant heat rate to rise (*i.e.*, cause efficiency to fall). Degradation in the performance of the HRSG, steam turbine, and ancillary equipment such as pumps and motors is also expected to occur over the course of a major maintenance cycle.

As a result of these adjustments, the emission rates are as follows:

Output-Based Emission Rates

Turbine Model	Duct Burner Firing?	Gross Heat Rate (Btu/kWh) (HHV)	Output-Based Emission Rate (lb CO_2/MWh), gross
GE 7HA.02	No	7,047	837.6
	Yes	7,395	879.0

Note: Information provided in the heat rate column is for informational purposes only and is not intended to be enforceable.

Therefore, Colorado Bend II Power is proposing a gross heat rate of 7,395 Btu/kWh (HHV) and a gross output-based emission rate of 879.0 lb CO_2/MWh, both on a 12-month rolling average, as BACT limits for the project.

The gross heat rate and output-based emission rate calculations for the GE 7HA.02 model turbine are provided in Table 5-1 of this application. Since the plant heat rate varies according to turbine operating load and the amount of duct burner firing, Colorado Bend II Power proposes to demonstrate compliance with the proposed heat rate utilizing a 12-month rolling average compliance period. This compliance period is necessary to accommodate conditions where there may be extended periods of operation at low loads and the potential for high use of duct burners.

On January 8, 2014, EPA published in the Federal Register its proposed new source performance standard for emissions of CO_2 for new affected fossil fuel-fired electric utility generating units. EPA proposed two options for codifying the requirements: (1) amend existing NSPS Subparts Da (Standards of Performance for Electric Utility Steam Generating Units) and KKKK (Standards of Performance for Stationary Combustion Turbines), or (2) create new NSPS Subpart TTTT (Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units). The proposed rule would only apply to new stationary fossil fuel-fired electric generating units that have a design heat input greater than 250 MMBtu/hr and sell more than one-third of their potential output and more than 219,000 MWh net electrical output to the grid on an annual basis. The EPA proposed that combustion turbines meet an annual average output-based standard of 1,000 lb

CO_2/MWh gross for natural gas-fired units that have heat inputs greater than 850 MMBtu/hr. The proposed CO_2 emission rates for the Colorado Bend II combined-cycle turbines are well within the emission limit in the proposed NSPS Subparts KKKK and TTTT. In addition, the proposed 12-month rolling average compliance period is consistent with the proposed NSPS. The method for calculating emissions will be similar to the methodology stated in the draft NSPS KKKK and TTTT in that the emissions and the generator output will be summed at the end of each month for these time periods and the monthly emission rates will be calculated at that point.

Colorado Bend II Power performed a search of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) for permitted natural gas-fired combined-cycle combustion turbine generators and found numerous entries which address BACT for GHG emissions. The results of the RBLC search are presented in Appendix A of this application. Appendix A also shows the proposed GHG limits for combined cycle projects in Texas for which GHG permits are pending. Although there are some differences in the combustion turbine technologies, as well as differences in the basis of the BACT limits (i.e. net vs. gross output basis, with or without duct burners, mass emission rate limits or not, etc.), the summary presented above demonstrates that the limits proposed by Colorado Bend II Power are comparable to limits for other recent projects, permitted and proposed.

Although several are under construction, none of the projects that have received GHG permits have yet begun operation. Therefore, long-term compliance with permit limits has yet to be demonstrated.

The GHG BACT limits should meet the twin goals of allowing flexible operation of the combined-cycle unit as well as limiting mass emissions of GHG to the atmosphere. Output-based limits have the desired effect of promoting operators to seek thermal efficiencies in their unit operations, resulting in increased electrical output for reduced GHG emissions, while ton per year limits restrict the total mass emissions of GHG to the atmosphere. Therefore, Colorado Bend II Power concludes that the combination of the ton per year and output-based limits presented in this application are BACT for this project.

5.2 BACT FOR SF_6 INSULATED ELECTRICAL EQUIPMENT

5.2.1 Step 1: Identify All Available Control Technologies

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

Another available technology that was considered in this analysis is to substitute another, non-GHG 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.*[24]

5.2.2 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.[25] 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 substituting another, non-GHG substance for SF_6 as the dielectric material in the breakers is not technically feasible.

5.2.3 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 only control technology that is technically feasible for this application.

5.2.4 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-GHG substance for SF_6 as the dielectric material in the breakers is not technically feasible.

5.2.5 Step 5: Select BACT

Based on this top-down analysis, Colorado Bend II Power concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection is BACT. The circuit breakers will be designed to meet the latest American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers.[26] The proposed SF_6 circuit breakers will each 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 leaks to the attention of the operations/maintenance staff before

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[24] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6,* NIST Technical Note 1425, Nov.1997.
[25] *Id.* at 28 – 29.
[26] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*.

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.

Colorado Bend II Power will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use.[27] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

The RBLC lists four facilities (Palmdale Hybrid Power Project, LCRA Thomas C. Ferguson Plant, Calpine Deer Park Energy Center, and St. Joseph Energy Center) with GHG BACT requirements for SF_6 circuit breakers. These BACT requirements are mainly annual CO_2e emission limits, based on either a rolling 12-month or 365-day period. In addition, the St. Joseph Energy Center has an SF_6 leak rate restriction of 0.5% per year, which is equivalent to the leak rate used in the fugitive SF_6 emissions calculations for the proposed project.

5.3 BACT FOR AUXILIARY BOILER AND DEW POINT HEATERS

One natural gas-fired, nominally-rated 40-MMBtu/hr auxiliary boiler will be utilized to facilitate startup of the combined cycle units and maintain vacuum when the units are down. In addition, two natural gas-fired, nominally-rated 1.0-MMBtu/hr dew point heaters will be utilized as necessary to heat the natural gas fuel for the CTs.

5.3.1 Step 1: Identify All Available Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all available control technologies. The following technologies were identified as potential control options for the auxiliary boiler and small heaters:

- Carbon Capture and Sequestration;
- Use of low carbon fuels;
- Use of good operating and maintenance practices; and
- Energy efficient design.

As stated in the combustion turbine BACT discussion above, CCS was eliminated as possible BACT. The economics of applying such technology to the auxiliary boiler and small heaters is even more exacerbated due to the intermittent operations of the units as well as the low CO_2 concentration in the flue gas. As such, CCS will not be further evaluated as BACT for the boiler and heaters.

The boiler and heaters will utilize natural gas which is the lowest carbon fuel available at the Colorado Bend II site. Therefore, formation of CO_2 from combustion of the fuel will be minimized.

[27] *See* 40 C.F.R. Pt. 98, Subpt. DD.

Good operating and maintenance practices for the boiler and heaters include following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing in the combustion zone; and maintaining the proper air-to-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 unit.

The energy efficient design of the boiler and heaters includes insulation to retain heat within the unit and a computerized process control system that will optimize the fuel/air mixture.

5.3.2 Step 2: Eliminate Technically Infeasible Options

CCS was discussed previously for the combined cycle units, and it was determined that it is technically infeasible for application on a commercial scale power plant at this time. For the same reasons, CCS is technically infeasible for the auxiliary boiler and small heaters.

5.3.3 Step 3: Rank Remaining Control Technologies

As discussed above, the only potential post-combustion option for GHG removal is technically infeasible for application on the boiler and small heaters at this time. As all of the energy efficiency related processes, practices, and designs discussed in Section 5.3.1 of this application are being proposed for the boiler and heaters, a ranking of the control technologies is not necessary for this application.

5.3.4 Step 4: Evaluate Most Effective Controls and Document Results

As all of the energy efficiency related processes, practices, and designs discussed in Section 5.3.1 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.

5.3.5 Step 5: Select BACT

Colorado Bend II Power reviewed the GHG permit entries listed in EPA's RBLC and found a few projects with GHG emission limits for natural gas-fired auxiliary boilers and heaters. The emission limits given in the RBLC for these units are shown in Appendix A of this application. Although there are differences in the annual mass emission limits for auxiliary boilers and heaters based on unit size and annual operation, which varies from project to project, Colorado Bend II Power's emission rate of 117 lb CO_2/MMBtu matches the lowest such emission rates shown in Appendix A.

Based on the review of emission rates for other auxiliary boilers and BACT controls shown in the RBLC, Colorado Bend II Power concludes that the use of natural gas as a low carbon fuel; good operating and maintenance practices; and the energy efficient design are BACT for the auxiliary boiler and two small heaters.

5.4 BACT FOR EMERGENCY ENGINES

The Colorado Bend II site will be equipped with one nominally rated 2,937-hp diesel-fired emergency generator to provide electricity to the facility in case of power failure and one nominally rated 250-hp diesel-fired water pump to provide water in the event of a fire.

5.4.1 Step 1: Identify All Available Control Technologies

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

- Use of low carbon fuel;
- Use of good operating and maintenance practices; and
- Low annual capacity factor.

Engine options include engines powered with electricity, natural gas, or liquid fuel, such as gasoline or fuel oil.

Good operating and maintenance practices for the engines include the following:

- Operating with recommended fuel-to-air ratio recommended by the manufacturer; and
- Appropriate maintenance of equipment, such as periodic readiness testing.

Each emergency engine will be limited to 100 hours of non-emergency operation per year for purposes of maintenance checks and readiness testing.

5.4.2 Step 2: Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible. The purpose of the engines is to provide a power source during emergencies, which includes outages of the combustion turbines, natural gas supply outages, fires, and natural disasters, such as floods and hurricanes. As such, the engines must be available during emergencies. Electricity and natural gas may not be available during an emergency and therefore cannot be used as an energy source for the emergency engines.

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 gasoline or diesel fuels. 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 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 emergency engines.

Because of the need to store the emergency 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 emergency engines. Also, a low annual capacity factor for the engines is technically feasible since the engines will only be operated either for readiness testing or for actual emergencies.

5.4.3 Step 3: Rank Remaining Control Technologies

Since the remaining technically feasible processes, practices, and designs discussed in Section 5.4.1 of this application for the emergency engines are being proposed for the engines, a ranking of the control technologies is not necessary for this application.

5.4.4 Step 4: Evaluate Most Effective Controls and Document Results

Since the remaining technically feasible processes, practices, and designs discussed in Section 5.4.1 of this application for the emergency engines are being proposed for the engines, an evaluation of the most effective controls is not necessary for this application.

5.4.5 Step 5: Select BACT

As a result of this analysis, appropriate operation of the engines through proper fuel-to-air ratios and maintenance based on recommended readiness testing (i.e., good combustion practices) and low annual hours of operation are selected as BACT for the proposed emergency engines. Note that the operating restriction of 100 hours per year for the proposed emergency engines matches the lowest operating restriction shown in the RBLC for similar units.

The RBLC lists multiple facilities with GHG BACT requirements for diesel fuel-fired emergency engines. The Entergy Louisiana Ninemile Point facility has CO_2, CH_4, and N_2O lb/MMBtu emission limits for its emergency generator and fire pump engine. The Arcadis-U.S. Oregon Clean Energy Center has CO_2e tpy emission limits for its emergency generator and fire pump engine that are based on rolling 12-month periods, and both have an annual operating restriction of 500 hours per year. The Hickory Run Energy Station has CO_2e tpy emission limits on its diesel generators that are based on a rolling 12-month periods. The St. Joseph Energy Center has CO_2e tpy emission limits on its diesel generators, based on a rolling 12-month period, and each has an annual operating restriction of 500 hours per year. The LCRA Thomas C. Ferguson Plant has a heat input limit, an annual operating restriction of 100 hours per year for non-emergency operations, GHG/CO_2e lb/hr emission limits (rolling 30-day average), and GHG/CO_2e tpy emission limits (rolling 365-day average) on its emergency generators. The Berks Hollow Ontelaunee facility has CO_2e tpy emission limits on its emergency generators. The Salem Harbor Redevelopment Project has CO_2e lb/MMBtu and annual emission limits on its emergency generators, and each has an annual operating restriction of 300 hours per year. The LaPaloma Energy Center has just an annual operating restriction of 100 hours per year on each of its emergency generators with no emission limits. Most of these facilities also have a BACT requirement of good combustion practices for the emergency engines.

5.5 BACT FOR NATURAL GAS FUGITIVES

The proposed project will include natural gas piping components. These components are potential sources of methane and CO_2 emissions due to emissions from rotary shaft seals, connection interfaces, valve stems, and similar points.

5.5.1 Step 1: Identify All Available Control Technologies

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

- Implementation of a leak detection and repair (LDAR) program using a hand-held analyzer;
- Implementation of alternative monitoring using a remote sensing technology such as infrared cameras; or
- Implementation of an audio/visual/olfactory (AVO) leak detection program.

5.5.2 Step 2: Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible. The use of instrument LDAR and remote sensing technologies are technically feasible. Since pipeline natural gas is odorized with a small amount of mercaptan, an AVO leak detection program for natural gas piping components is technically feasible.

5.5.3 Step 3: Rank Remaining Control Technologies

The use of a LDAR program with a portable gas analyzer meeting the requirements of 40 CFR 60, Appendix A, Method 21, can be effective for identifying leaking methane. Quarterly instrument monitoring with a leak definition of 10,000 part per million by volume (ppmv) (TCEQ 28M LDAR Program) is generally assigned a control efficiency of 75% for valves, relief valves, sampling connections, and compressors and 30% for flanges.[28] Quarterly instrument monitoring with a leak definition of 500 ppmv (TCEQ 28VHP LDAR Program) is generally assigned control efficiencies of 97% for valves, relief valves, and sampling connections, 85% for compressors, and 30% for flanges.[29] The EPA has allowed the use of an optical gas imaging instrument as an alternative work practice for a Method 21 portable analyzer for monitoring equipment for leaks in 40 CFR 60.18(g). For components containing inorganic or odorous compounds, periodic AVO walk-

[28] Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, TCEQ, Oct. 2000
[29] Id. at page 52.

through inspections provide predicted control efficiencies of 97% control for valves, flanges, relief valves, and sampling connections, and 95% for compressors.[30]

5.5.4 Step 4: Evaluate Most Effective Controls and Document Results

The frequency of inspection and the low odor threshold of mercaptans in natural gas make AVO inspections an effective means of detecting leaking components in natural gas service. As discussed in Section 5.5.3, the predicted emission control efficiency is comparable to the LDAR programs using Method 21 portable analyzers.

5.5.5 Step 5: Select BACT

Due to the very low volatile organic compound (VOC) content of natural gas, Colorado Bend II Power will not be subject to any VOC leak detection programs by way of its State/PSD air permit, TCEQ Chapter 115–Control of Air Pollution from Volatile Organic Compounds, New Source Performance Standards (40 CFR Part 60), National Emission Standard for Hazardous Air Pollutants (40 CFR Part 61); or National Emission Standard for Hazardous Air Pollutants for Source Categories (40 CFR Part 63). Therefore, any leak detection program implemented will be solely due to potential greenhouse emissions. Since the uncontrolled CO_2e emissions from the natural gas piping represent approximately 0.01% of the total site wide CO_2e emissions, any emission control techniques applied to the piping fugitives will provide minimal CO_2e emission reductions.

Based on this top-down analysis, Colorado Bend II Power concludes that a daily AVO inspection program is BACT for piping components in natural gas service.

[30] Id. at page 52.

MAP OF POTENTIAL GEOLOGIC STORAGE SITES AND CO_2 PIPELINES

GCCC Field Tests for Monitoring and Verification Technologies DOE NETL support

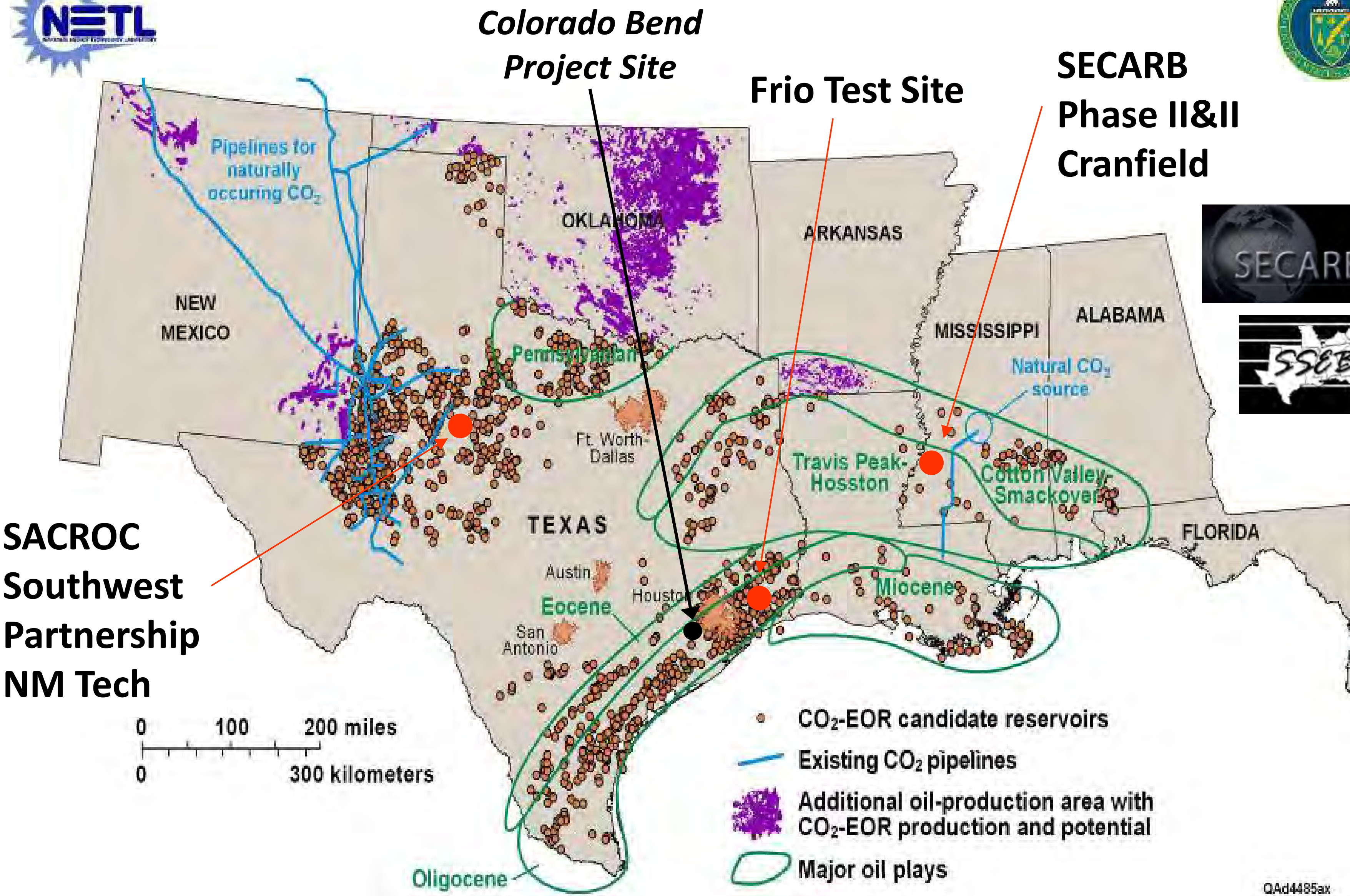

Table 5-1
GHG Emission Calculations - Calculation of Design Heat Rate and Output Limits for GE 7HA.02
Colorado Bend II

Without Duct Burner Firing

	Gross Output Basis	
Base Heat Rate:	**6,248**	Btu/kWh (HHV)
Design Margin:	3.3%	
CTG Degradation Margin:	6.0%	
Plant Degradation Margin:	3.0%	
Adjusted Base Heat Rate with Compliance Margins:	**7,047**	Btu/kWh (HHV)

EPN	Base Heat Rate (Btu/kWhr)	Electrical Output Basis	Heat Input Required to Produce 1 MW (MMBtu/MWhr)	Pollutant	Emission Factor (lb/MMBtu)[1]	lb GHG/MWhr[2]	Global Warming Potential[3]	lb CO_2e/MWhr[4]
CTDB3-A and -B	7,047	Gross	7.05	CO_2	118.86	837.55	1	837.55
				CH_4	2.2E-03	1.55E-02	25	3.88E-01
				N_2O	2.2E-04	1.55E-03	298	4.63E-01
					Total:	**837.6**		**838.4**

With Duct Burner Firing

	Gross Output Basis	
Base Heat Rate:	**6,557**	Btu/kWh (HHV)
Design Margin:	3.3%	
CTG Degradation Margin:	6.0%	
Plant Degradation Margin:	3.0%	
Adjusted Base Heat Rate with Compliance Margins:	**7,395**	Btu/kWh (HHV)

EPN	Base Heat Rate (Btu/kWhr)	Electrical Output Basis	Heat Input Required to Produce 1 MW (MMBtu/MWhr)	Pollutant	Emission Factor (lb/MMBtu)[1]	lb GHG/MWhr[2]	Global Warming Potential[3]	lb CO_2e/MWhr[4]
CTDB3-A and -B	7,395	Gross	7.40	CO_2	118.86	878.97	1	878.97
				CH_4	2.2E-03	1.63E-02	25	4.08E-01
				N_2O	2.2E-04	1.63E-03	298	4.86E-01
					Total:	**879.0**		**879.9**

Notes

1. CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.
2. *CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4*

$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2000$

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

F_c = Carbon based F-factor,1040 scf/MMBtu

H = Heat Input (MMBtu/yr)

MW_{CO2} = Molecule weight of CO_2, 44.0 lb/lbmole

3. *Global Warming Potential factors revised as part of amendments made to the Greenhouse Gas Reporting Rule (78 FR 71904).*
4. *Example calculation: GHG emissions (lbs) x Global Warming Potential / 1 MW = lb CO_2e/MWhr*

6.0 OTHER PSD REQUIREMENTS

6.1 IMPACTS ANALYSIS

An impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *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.*[31]

An impacts analysis for non-GHG emissions is being submitted with the criteria pollutant NSR permit application submitted to the TCEQ.

6.2 GHG PRECONSTRUCTION MONITORING

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

> *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.*[32]

A pre-construction monitoring analysis for non-GHG emissions is being submitted with the State/PSD/Nonattainment application submitted to the TCEQ.

6.3 ADDITIONAL IMPACTS ANALYSIS

A PSD additional impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *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,*

[31] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* at 47-49.
[32] *Id.* at 48.

> *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 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.*[33]

A NSR additional impacts analysis for non-GHG emissions is being submitted with the NSR application submitted to the TCEQ.

[33] *Id.* at 48.

7.0 PROPOSED GHG MONITORING PROVISIONS

Colorado Bend II Power proposes to monitor CO_2 emissions by monitoring the quantity of fuel combusted in the turbines and HRSGs and performing periodic fuel sampling as specified in 40 CFR 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 Colorado Bend II 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 GCV in equation F-7b of 40 CFR 75, Appendix F. The site-specific F_c factor will be re-determined annually in accordance with 40 CFR 75, Appendix F, §3.3.6.

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

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

$$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2{,}000$$

Where:

W_{CO2} = CO_2 *emitted from combustion, tons/hr*

MW_{CO2} = *molecular weight of* CO_2*, 44.0 lb/lbmole*

F_c = *Carbon based F-factor, (1,040 scf/MMBtu for natural gas* *<u>or a site-specific</u>* F_c *<u>factor</u>)*

H = Hourly heat input in MMBtu, as calculated using the procedure in 40 CFR 75, Appendix F, §5)

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 75 Appendix D are as follows:

- *Fuel flow meter: meet an accuracy of 2.0 %, required to be tested once each calendar quarter (40 CFR 75, Appendix D, §2.1.5 and §2.1.6(a)); and*
- *GCV: determine the GCV of pipeline natural gas at least once per calendar month (40 CFR 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 98, Subpart D). Subpart D requires electric generating sources that report CO_2 emissions under 40 CFR 75 to report CO_2 under 40 CFR 98 by converting CO_2 tons reported under Part 75 to metric tons.

In addition, the recently proposed new source performance standards for emissions of CO_2 for new affected fossil fuel-fired electric utility generating units would allow electric generating units firing gaseous fuel and/or liquid fuel to determine CO_2 mass emissions by monitoring fuel combusted in the affected Electric Generating Unit and using either a default F_c factor listed in 40 CFR 75, Appendix G or a site specific F_c factor determined in accordance with 40 CFR 75, Appendix F. Therefore, Colorado Bend II Power's proposed CO_2 monitoring method would be consistent with the proposed NSPS Subparts KKKK and TTTT.

APPENDIX A

SUMMARY TABLES OF PERMITTED GHG LIMITS FROM THE RBLC

Table A-1. Combined-cycle combustion turbine projects with GHG permit limits listed in the RBLC database (with the exception of projects highlighted in yellow, which represent projects not found in RBLC)

Facility Name	Location	Permit Date & Number	Process/Equipment	Maximum Throughput	GHG Permit Limit(s)	Notes:
Russell City Energy Center	Alameda Co., California	2/3/2010, 15487	Two Siemens/Westinghouse 501F CTG/HRSG sets		7,730 Btu/kWh	Based on an annual heat rate performance test.
Entergy Louisiana Ninemile Point Electric Generating Plant	Jefferson Co., Louisiana	8/16/2011, PSD-LA-752	2 CCGT with duct burners (1827 MW total)	7146 MMBtu/hr	CO2e: 7630 Btu/KWh (HHV, gross), annual average for each CCGT	Operate properly and perform necessary routine maintenance, repair, and replacement to maintain heat rate at or below 7630 Btu/KWh.
			Auxiliary Boiler	338 MMBtu/hr	CO2: 117 lb/MMBtu Methane: 0.0022 lb/MMBtu N2O: 0.0002 lb/MMBtu	Proper operation and good combustion practicices
			Diesel Fired Emergency Generator (1250 HP)		CO2: 163 lb/MMBtu Methane: 0.0061 lb/MMBtu N2O: 0.0014 lb/MMBtu	Proper operation and good combustion practicices
			Diesel Fired Fire Water Pump (350 HP)		CO2: 163 lb/MMBtu Methane: 0.0061 lb/MMBtu N2O: 0.0014 lb/MMBtu	Proper operation and good combustion practicices
Palmdale Hybrid Power Project	Los Angeles Co., California	10/18/2011, SE 09-01	570 MW Natural Gas-fired CCGT with an integrated 50 MW solar thermal plant	154 MW (each CCGT) Shutdown Throughput Limit: 110 MMBtu/hr	CO2e: 774 lb/MWh, 365-day rolling avg., 7319 BTU/KWh, 365-day rolling avg. (both facility-wide)	TWO NATURAL GAS-FIRED COMBUSTION TURBINE-GENERATORS (CTGS) RATED AT 154 MEGAWATT (MW, GROSS) EACH, TWO HEAT RECOVERY STEAM GENERATORS (HRSG), ONE STEAM TURBINE GENERATOR (STG) RATED AT 267 MW, AND 251 ACRES OF PARABOLIC SOLAR-THERMAL COLLECTORS WITH ASSOCIATED HEAT-TRANSFER EQUIPMENT
			Auxiliary Heater (boiler)	40 MMBtu/h	No emission limits	Requires annual boiler tune-ups, NO EMISSION LIMITS
			SF-6 Circuit Breakers		CO2e: 9.56 TPY, 12-month rolling avg.	0.5% BY WT ANNUAL LEAKAGE RATE 10% BY WT LEAK DETECTION SYSTEM
			Auxiliary Boiler	110 MMBtu/h	No emission limits	Requires annual boiler tune-ups
Lower Colorado River Authority Thomas C. Ferguson Power Plant	Llano Co., Texas	11/10/2011, PSD-TX-1244-GHG	Two new (GE 7FA) CCGT units (590 MW)	1746 MMBtu/h (each unit)	CO2e: 908,957.6 lb/h (30-day rolling avg.), 153,392.1 lb/h (SU/SD only), Methane: 16.8 TPY (365-day rolling avg.) and 2.84 lb/h (SU/SD only)	Natural gas-fired GE 7FA combustion turbine unit, U1-STK. and is rated at Max. based-load output of 195 MW and vented to a Heat Recovery Steam Generator (HRSG) that is equipped with an SCR and an Oxidation Catalyst.
			Diesel Fired Emergency Generator (1340 HP)	93.8 MMBtu/h	CO2e: 15,314 lb/h, 30-day rolling avg., and 765.7 TPY, 365-day rolling avg.; CO2: 15,263.2 lb/h, 30-day rolling avg. and 763.2 TPY, 365-day rolling avg.	Limited to 100 hours operation per year for non-emergency activities.
			Diesel-Fired Fire Water Pump	617 HP	CO2e: 7,052 lb/h, 30-day rolling avg., and 352.6 TPY, 365-day rolling avg.; CO2: 7,027.8 lb/h, 30-day rolling avg., and 351.4 TPY, 365-day rolling avg.	Limited to 100 hours operation per year for non-emergency activities.
			SF-6 Insulated Circuit Breakers (fugitives)	SF-6 stated for hourly limit, CO2e for annual TPY limit	131 (CO2e) TPY, 365-day rolling avg., 0.006 lb/hr	SF6 emission rates (in TPY) are measured as CO2e. (See Final Permit, Page 7)
			Natural gas fugitives		Methane: 16.2 TPY, CO2e: 327.2 TPY, 365-day rolling avg.	Because the emissions from this unit are calculated to be 96% methane (CH4), the remaining GHG pollutant emissions (CO2) are not accounted for.
Wolverine Power Supply Cooperative Sumpter Power Plant	Wayne Co., Michigan	11/17/2011, 81-11	130 MW combined-cycle combustion turbine		954 lb/MWh, 12-month rolling avg.	Converting a SCGT to a CCGT with a non-fired HRSG. Estimated efficiency is 49.6% thermal efficiency (design is gross summer 87 degrees ambient and includes a 6% factor for performance degradation).
			Diesel fuel-fired combustion engine	732 HP	716.6 lb/h (CO2e) TEST	Good combustion practices only.
Pioneer Valley Energy Center	Hampden Co., Massachusetts	4/12/2012, 052-042-MA15	One CTG/HRSG set (431 MW)		Initial compliance: 825 lb CO2e/MWh to grid Life-of-Facility: 895 lb CO2e/MWh to grid, 365-day rolling avg.	

Table A-1. Combined-cycle combustion turbine projects with GHG permit limits listed in the RBLC database (with the exception of projects highlighted in yellow, which represent projects not found in RBLC)

Gateway Green Energy Gateway Cogeneration 1 Smart Water Project	Prince George Co., Virginia	8/27/2012, 52375-002	2 Combined-cycle Combustion Turbines, Rolls Royce Trent 60 WLE with HRSG, no duct burners, 160 MW	593 MMBtu/hr	295961 T/Yr per rolling 12-months 1050 lb CO2/MWh, 12-mo. avg.	Facility has dual-fuel capabilities. Controlled by the use of low carbon fuels and high efficiency design. The heat rate shall be no greater than 8,983 Btu/kW-h (HHV, gross). Initial compliance testing, using ASME Performance Test Code on Overall Plant Performance (ASME PTC 46-1996).
Cricket Valley Energy Center	Dutchess Co., New York	9/27/2012, 3-1326-00275/00004	Three GE 7FA CTG/HRSG sets		7,605 Btu/KWh (HHV) CTG/HRSG sets: 3,576,943 tpy CO2e, 12-mo rolling Facility-wide: 3,597,766 tpy CO2e, 12-mo rolling	Output-based limit excludes DB firing; compliance based on initial and annual heat rate performance testing, with data corrected to ISO conditions
Moxie Liberty Asylum Power Plant	Bradford Co., Pennsylvania	10/10/2012, 08-00045A	Option One: Two Mitsubishi M501GAC CTG/HRSG sets or Option Two: Two Siemens SGT6-8000H CTG/HRSG sets		Option 1: 7,458 Btu/kWh Option 2: 7,475 Btu/kWh Both based on HHV basis	Emission limit is for operations without duct burners firing No documentation as to whether this is based on a net or gross power production value
NRG Energy Center Dover	Kent Co., Delaware	10/31/2012, AQM-001/00127 (R-2)(REV-1)	GE LM6000 (52 MW) and HRSG (18 MW)	655 MMBtu/hr	1085 lb/MWh (gross), 12-month rolling avg.	The facility operates two electric generation units and an auxilliliary steam boiler. 500 MMBTU/hr Gas Turbine (Model: GE LM6000) rated at 52 MW and 155 MMBTU/hr Heat Recovery Steam Generator rated at 18 MW.
Calpine Corp. Channel Energy Center	Harris Co., Texas	11/29/2012, PSD-TX-955-GHG	1 on 1 CCGT along with upgrade of FD2 CGT to FD3 series	Duct Burner: 475 MMBtu/hr	Phase I: CO2: 0.460 tons/MWh and 7730 Btu/KWh (30 day avg.) and 984,3936 TPY of CO2e CH4: 18.22 TPY N2O: 1.82 TPY CO2: 985,340 TPY Phase II: CO2: 0.460 tons per MWh and 7730 Btu/KWh (30 day avg.) and 1,002,391 TPY CH4: 18.55 TPY N2O: 1.86 TPY	Siemens FD2-501F exhausting to a HRSG and CTG3 upgrade to FD3 Series.
Calpine Corp. Deer Park Energy Center	Harris Co., Texas	11/29/2012, PSD-TX-979-GHG	CTG5/HRSG5: Initial 180 MW combined-cycle CTG (Siemens FD-2) which will be upgraded to FD-3 series turbine		0.46 T (CO2)/MWh, 30-day rolling avg. and 1,044,629 TPY, 365-day rolling avg. Methane: 19.34 TPY, 365-day avg. N2O: 1.93 TPY, 365-day avg.	Natural Gas-Fired Siemens FD2-Series 501F Combustion Turbine Generators (CTGs) rated at a maximum base-load electric output of approximately 168 MW and venting to a dedicated Heat Recovery Steam Generator (HRSG) that is equipped with a Selective Catalytic Reduction (SCR).
			CTG5/HRSG5: combined-cycle CTG after upgrade (Siemens FD-3)		0.46 T (CO2)/MWh, 30-day rolling avg. and 1,062,627 TPY, 365-day rolling avg. Methane: 19.67 TPY, 365-day avg., N2O: 1.97 TPY, 365-day avg.	Natural Gas-Fired Siemens FD3-Series 50I F Combustion Turbine Generators (CTGs) rated at a maximum base-load electric output of approx i mately 180 M W and venting to a dedicated Heat Recovery Steam Generator (HRSG) that is equipped with a Selective Catalytic Reduction (SCR).
			NG-FUG (natural gas emissions from piping components		Methane: 2.84 TPY, 365-day avg., CO2: 0.11 TPY, 365-day avg.	Fugitive Natural l Gas emissions from piping components (including valves and flanges)
			SF-6 circuit breaker (1) fugitives		0.0002 TPY (SF-6), 365-day rolling avg.	SF6 Insulated Electrical Equipment (i.e., circuit breakers) consisting of one new 72 lb SF6 insulated generator circuit breaker.
St. Joseph Energy Center	St. Joseph, Indiana	12/3/2012, 141-31003-00579	Four natural gas combined-cycle combustion turbines	2300 MMBtu/h (per unit)	7646 Btu/KW-h (CO2e) (for each CCGT) and 4,885,000 TPY (CO2e) 12-month rolling basis (all four CCGTs combined)	Each turbine is equipped with DLN burners, natural gas-fired duct burners and a HRSG. Units have SCR and oxidation catalyst. Combined nominal output is 1350 MW.
			Four natural gas combined-cycle combustion turbines (start-up/shut-down cycle)		2125 lb/event* and 407.5 TPY (CO2e) 12-month rolling basis	Limit one uses the cold start emission totals, per CCCT, as a short-term limit during SU/SD events. Limit two is combined emissions from CCCT1-4 for the duration of the combined SU/SD event. *Event=one start-up or one shut-down.

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			Two auxiliary boilers	80 MMBtu/h	81,996 TPY 12-month basis and 80% HHV	Natural gas-fired boiler designed for 80% efficiency as determined by initial performance test. O&M practices, combustion tuning, oxygen trim controls & analyzers; economizer-energy efficient refractory, condensate return system, insulate steam and hot lines. Minimization of gas-side heat transfer surface deposits, turbulators for firetube boiler steam line maintenance.
			Two firewater pump diesel engines (371 BHP each)		172 TPY (CO2e) 12-month basis, both units combined	Diesel fuel-fired. Compliance determined at the end of the month
			Two Emergency Diesel Generators (1006 HP each)	500 hr/yr limit	1186 TPY (CO2e) 12-month rolling basis	Diesel fuel-fired, Compliance determined at the end of each month; TPY limit is for all three emergency generators combined
			One Emergency Diesel Generator (2012 HP)			
			SF-6 circuit breakers (6)		0.0009 TPY SF-6, 12-month rolling basis and a 0.5%/yr design leak rate	Compliance determined at the end of each month. A density alarm for leak detection and the use of totally enclosed and pressurized circuit breakers is required.
Calpine Corp. Garrison Energy Center	Kent Co., Delaware	1/30/2013, APC-2012/0098	One 309 MW GE combined-cycle combustion turbine primarily fired on natural gas with low sulfur diesel backup fuel.	2260 MMBtu/hr	1,006,304 TPY (CO2e) 12-month rolling basis	Unit restricted to firing natural gas and low sulfur distillate fuel
Virginia Electric Power-Brunswick Station	Brunswick Co., Virginia	2/12/2013	Three Mitsubishi M501 GAC combustion turbines with HRSG duct burners	3442 MMBtu/hr	7,500 Btu/kWh (net HHV) output; 920 lbs CO2/MWh (net HHV)	12 operating month average
			Auxiliary Boiler	66.7 MMBtu/hr	117 lb (CO2e)/MMBtu	Natural gas-fired and permitted for 8760 hrs/yr; BACT is use of pipeline quality natural gas and fuel efficient design and operation
Midland Cogeneration Venture	Midland, Co., Michigan	4/23/2013	Two CTGs with HRSG with 249 MMBtu/hr duct burners (3 possible turbine models: GE 7FA, Siemens SGT6-5000F(4) or SGT6-5000F(5)); 2 x 2 x 1 configuration	2237 MMBtu/hr (each)	995 lb (CO2e)/MW-hr (gross output) without duct firing; 1,071 lb/MW-hr (gross output) with duct firing	Compliance based on12-month rolling average
Hickory Run Energy Station	Lawrence Co., Pennsylvania	4/23/2013, 37-337A	900 MW nominal Combined Cycle Units #1 and #2 with duct burners.	3.4 MMCF/hr	3,665,974 TPY (CO2e) 12-month rolling total for both units	Permittee will select and install an of the turbine options listed: 1. General Electric 7FA (GE 7FA) 2. Siemens SGT6-5000F 3. Mitsubishi M501G (Mitsubishi G) 4. Siemens SGT6-8000H (Simens H). The emissions listed are for the Siemens SGT6-8000H unit.
			Auxiliary Boiler	40 MMBtu/hr	13,696 TPY (CO2e) 12-month rolling basis	Natural gas-fired
			Emergency Generator (1135 BHP-750 KW)	7.8 MMBtu/hr	80.5 TPY (CO2e) 12-month rolling basis.	Ultra low sulfur distillate fuel
			Emergency Firewater Pump (450 BHP)	3.25 MMbtu/hr	33.8 TPY (CO2e) 12-month rolling basis.	Ultra low sulfur distillate fuel
Arcadis-U.S. Oregon Clean Energy Center	Lucas Co., Ohio	6/18/2013, P0110840	2 Combined-cycle Combustion Turbines, Mitsubishi, with duct burners	47,917 MMSCF/rolling 12-month avg.	318,404 lb/hr (CO2e), 1,394,611 T/Yr per rolling 12-months Additional limit: 840 lb/MWh CO2e (gross output). BACT is compliance with the proposed NSPS: 1000 lb/CO2/MWh (gross output). 99% of the CO2e is CO2. T/yr limit is for 2 turbines.	Two Mitsubishi 2932 MMBtu/hr combined-cycle combustion turbines, both with 300 MMBtu/hr duct burners. Using state of the art, high efficiency combustion technology
			2 Combined-cycle Combustion Turbines, Mitsubishi, without duct burners	47,917 MMSCF/rolling 12-month avg.	318,404 lb/hr (CO2e), 1,394,611 T/Yr per rolling 12-months Additional limit: 840 lb/MWh CO2e (gross output). BACT is compliance with the proposed NSPS: 1000 lb/CO2/MWh (gross output). 99% of the CO2e is CO2. T/yr limit is for 2 turbines.	Two Mitsubishi 2932 MMBtu/hr combined-cycle combustion turbines without duct burners. Using state of the art, high efficiency combustion technology
					318,404 lb/hr (CO2e), 1,435,847 T/Yr per rolling 12-months.	

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			2 Combined-cycle Combustion Turbines, Siemens, with duct burners	51,560 MMSCF/rolling 12-month avg.	Additional limit: 840 lb/MWh CO2e (gross output). BACT is compliance with the proposed NSPS: 1000 lb/CO2/MWh (gross output). 99% of the CO2e is CO2. T/yr limit is for 2 turbines.	Two Siemens 2932 MMBtu/H combined cycle combustion turbines , both with 300 MMBtu/H duct burners, with dry low NOx combustors, SCR, and catalytic oxidizer.
					318,404 lb/hr (CO2e), 1,435,847 T/Yr per rolling 12-months.	Two Siemens 2932 MMBtu/H combined cycle combustion turbines , both with 300 MMBtu/H duct burners, with dry low NOx combustors, SCR, and catalytic oxidizer. Will install either 2 Siemens or 2 Mitsubishi, not both (not
			2 Combined-cycle Combustion Turbines, Siemens, without duct burners	51,560 MMSCF/rolling 12-month avg. (RBLC listed this as a 515,600 MMBtu avg. but it is a misprint)	Additional limit: 840 lb/MWh CO2e (gross output). BACT is compliance with the proposed NSPS: 1000 lb/CO2/MWh (gross output). 99% of the CO2e is CO2. T/yr limit is for 2 turbines.	
			Auxiliary Boiler	99 MMBtu/hr	11,671 T/yr CO2e per rolling 12-month period	Has low-NOx burners, flue gas recirculation burning only natural gas. Boiler restricted to 2000 hours of ops per rolling 12-months.
			Emergency Generator	2250 KW	878 T/yr CO2e per rolling 12-month period	Restricted to 500 hours of operation per rolling 12-months
			Emergency Fire Pump Engine	300 HP	87 T/yr CO2e per rolling 12-month period	223.8 kW. Emergency fire pump engine restricted to 500 hours of operation per rolling 12 months.
Consumers Energy Company - Thetford	Genesee Co., Michigan	7/25/2013 191-12	4 Combined-cycle Combustion Turbines, with duct burners	2,587 MMBtu/hr per CTG or 2,688 MMBtu/hr per CTG	1,386,286 T/yr CO2e per rolling 12-month period for each combined cycle unit	
			2 Auxiliary Boilers	100 MMBtu/hr each; fuel use limied to 416.3 MMSCF/rolling 12-month period	24,304 T/yr CO2e per rolling 12-month period per boiler	Efficient combustion & energy efficiency are BACT controls
			2 Fuel Gas Heaters	12 MMBtu/hr each; fuel use limited to	6,156 T/yr CO2e per rolling 12-month period per heater	Efficient combustion & energy efficiency are BACT controls
			Emergency Fire Water Pump (315 hp)	100 hrs/yr	15.6 T/yr CO2e per rolling 12-month period	Proper design and ULSD fuel are BACT controls
La Paloma Energy Center	Cameron Co., Texas	11/6/2013 PSD-TX-1288-GHG	One 2X1 CTG/HRSG configuration One Auxiliary Boiler (150 MMBtu/hr) One Fire Water Pump (3.4 MMBtu/hr) One Emergency Generator (7.9 MMBtu/hr) 3 CTG Options: Option 1: GE 7FA Option 2: Siemens SGT6-5000F(4) Option 3: Siemens SGT6-5000F(5)	Gross Heat Rates with DB Firing (Btu/kWh)(HHV): Option 1: 7,861.8 Option 2: 7,649.0 Option 3: 7,679.0	Option 1: 934.5 lb CO2/MWh (gross) w/DB Option 2: 909.2 lb CO2/MWh (gross) w/DB Option 3: 912.7 lb CO2/MWh (gross) w/DB also: Startup emissions are limited to 500 hours per year and: 73 tons CO2/hr (option 1), 97 tons CO2/hr (option 2) and 94 tons CO2/hr (option 3). Maximum Heat Input During Startups: 1,230.6 (option 1) 1,626 (option 2) 1,584.2 (option 3)	Aux Boiler limited to 876 hours of operation per year and uses good combustion practices as BACT. Emergency generator and Fire Water Pump use good combustion practices and runtime limits of 100 hours/yr each as BACT
Berks Hollow Energy Assoc., LLC Ontelaunee	Berks Co., Pennsylvania	12/17/2013, 06-05150A	2 combined-cycle combustion turbines and two HRSGs with duct burners	3046 MMBtu/hr	1,000 lb CO2/MWh; 1,380,899 tpy (CO2e)	Natural gas-fired
			Auxiliary Boiler	40 MMBtu/hr	12,346 tpy (CO2e)	Natural gas-fired
			Emergency Generator	60 gal/hr	65 tpy (CO2e)	Fuel is ULSD
			Emergency Fire Water Pump	16 gal/hr	19 tpy (CO2e)	Fuel is diesel

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Salem Harbor Redevelopment Project	Essex Co., Massachusetts	1/30/2014, X254064	Two GE 7F Series 5 CTG/HRSG sets (150 MW each)		Initial compliance: 825 lb CO2e/MWh to grid Life-of-Facility: 895 lb CO2e/MWh to grid, 365-day rolling avg.	Emission limit is for operations with or without duct burners firing
			Auxiliary Boiler	80 MMBtu/hr; 6750 hrs/yr	119 lb CO2e/MMBtu	Natural gas-fired
			Emergency Generator (750 kW)	300 hrs/yr	162.85 lb CO2e/MMBtu; 181 tpy	Ultra low sulfur distillate fuel
			Fire Water Pump (371 BHP)	300 hrs/yr	162.85 lb CO2e/MMBtu; 66 tpy	Ultra low sulfur distillate fuel
Interstate Power & Light Marshalltown	Marshall Co., Iowa	4/14/2014, 13-A-499-P	Two combined cycle Siemens SGT6-5000F units with no duct burners	2258 MMBtu/hr (each)	951 lb CO2/MWh (gross ooutput); 1,318,647 tpy (CO2e)	Compliance based on12-month rolling average
			Auxiliary Boiler	60.1 MMBtu/hr	17,313 tpy (CO2e)	Natural gas-fired; fuel limit of 288.7 MMcuft per 12-mo rolling period; compliance based on 12-mo rolling average

Table A-2. Other combined-cycle combustion turbine projects in Texas with applications under review

Facility Name	Location	Permit Date & Number	Process/Equipment	GHG Permit Limit(s)	Notes:
Southern Company Trinidad Generating Facility	Henderson Co., Texas	(Application submitted June 2013)	One 1x1 CTG/HRSG configuration, MHI Model J CTG	922 lb CO_2/MWh (gross) w-o/DB Mass Limit: 1,674,804 TPY Heat Rate: 7,754 Btu/KWh (HHV, gross w-o DB)	Proposed limit on operation of NG-fired auxiliary boiler of 1,500 hours per year.
S.R. Bertron Unit 5	Harris Co., Texas	(Application submitted November 2012)	Either a 2X1 or 2X2 CCGT/HRSG configuration with fired HRSGs 3 CTG Options: GE 7FA.05 Mitsubishi 501GAC Siemens F95)	Option 1 Mass Limit: 1,203,838 TPY Option 2 Mass Limit: 1,344,347 TPY Option 3 Mass Limit: 1,468,007 TPY Heat Rate: 7,730 Btu/kWh (HHV) All based on supplementary firing.	No CO_2e/MWh output-based emission limit was proposed.
Cedar Bayou Unit 5	Chambers Co., Texas	(Application submitted November 2012)	Either a 2X1 or 2X2 CCGT/HRSG configuration with fired HRSGs 3 CTG Options: GE 7FA.05 Mitsubishi 501GAC Siemens F95)	Option 1 Mass Limit: 1,203,838 TPY Option 2 Mass Limit: 1,344,347 TPY Option 3 Mass Limit: 1,468,007 TPY Heat Rate: 7,730 Btu/kWh (HHV) All based on supplementary firing.	No CO_2e/MWh output-based emission limit was proposed.
E.S. Joslin Power Station	Calhoun Co., Texas	(Application submitted June 2012)	One 3X1 CTG/HRSG configuration (unfired)	Heat Rate: 7,730 Btu/kWh	No CO_2e/MWh output-based emission limit was proposed.