717 TEXAS AVENUE, SUITE 1000
HOUSTON, TX 77002

CALPINE CORPORATION

NYSE CPN

November 3, 2011

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
Channel Energy Center, LLC
Pasadena, Harris County, Texas

Mr. Robinson:

On behalf of Channel Energy Center, LLC, Calpine Corporation is hereby submitting this application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions for the construction of an additional cogeneration unit at the Channel Energy Center located in Harris Country, Texas. The state/PSD/Nonattainment application for non-greenhouse gas emissions is being submitted simultaneously to the Texas Commission on Environmental Quality (TCEQ).

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.

Calpine is committed to working closely with EPA Region 6 to support an expeditious review of this application. Calpine 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 Calpine's technical contact for this application, Ms. Jan Stavinoha, at jstavinoha@calpine.com or by telephone at (713) 570-4814.

Sincerely,

Patrick Blanchard
Director, EHS
Calpine Corporation

Enclosure

cc: Mr. Mike Wilson, P.E., Director, Air Permits Division, TCEQ

Mr. Larry Moon, P.E., Zephyr Environmental Corporation

PREVENTION OF SIGNIFICANT DETERIORATION GREENHOUSE GAS PERMIT APPLICATION FOR AN ADDITIONAL COMBINED CYCLE COGENERATION UNIT AT THE CHANNEL ENERGY CENTER HARRIS COUNTY, TEXAS

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

11-08-2011

Zephyr Environmental Corporation
STATE OF TEXAS
LARRY A. MOON
69515
LICENSED
PROFESSIONAL ENGINEER
F-102

SUBMITTED BY:
CHANNEL ENERGY CENTER, LLC
PASADENA, TEXAS 77506

PREPARED BY:
ZEPHYR ENVIRONMENTAL CORPORATION
2600 VIA FORTUNA, SUITE 450
AUSTIN, TEXAS 78746

NOVEMBER, 2011

zephyr

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APPENDICES

1.0 INTRODUCTION

Channel Energy Center, LLC (Channel Energy Center) owns and operates a combined-cycle cogeneration facility, located in Pasadena, Harris County, Texas. The facility is authorized under Permit Nos. 42179, PSD-TX-955, and N-021. The Channel Energy Center plant currently consists of two combustion turbine generators (CTGs) with duct fired heat recovery steam generators (HRSGs).

The purpose of this amendment is to authorize a third natural gas fired CTG/HRSG unit. The proposed unit is a combined cycle gas turbine in which the gas turbine generates electricity and the heat from the gas turbine exhaust will be used to produce steam in the heat recovery steam generator. Steam from the new CTG/HRSG unit will drive an existing on-site steam turbine generator (STG) to produce electricity or may be sold for use in an adjacent industrial facility. The recovery of energy from the gas turbine exhaust, which otherwise would be wasted, increases the energy efficiency of the unit.

On June 3, 2010, the EPA published final rules for permitting sources of Greenhouse Gases (GHGs) under the prevention of significant deterioration (PSD) and Title V air permitting programs, known as the GHG Tailoring Rule.[1] After July 1, 2011, new sources having the potential to emit more than 100,000 tons/yr of GHGs and modifications increasing GHG emissions more than 75,000 tons/yr on a carbon dioxide equivalent (CO_2e) basis at existing major sources are subject to GHG PSD review, regardless of whether PSD was triggered for other pollutants.

On December 23, 2010, EPA issued a Federal Implementation Plan (FIP) authorizing EPA to issue PSD permits in Texas for GHG sources until Texas submits the required SIP revision for GHG permitting and it is approved by EPA.[2]

The Channel Energy Center project for the addition of the third CTG/HRSG unit triggers PSD review for GHG regulated pollutants because the project will increase GHG emissions by more than 75,000 tons/yr and the site is considered an existing major source. Included in this application are a project scope description, GHG emissions calculations, GHG netting analysis, and a GHG Best Available Control Technology (BACT) analysis.

[1] 75 FR 31514 (June 3, 2010).

[2] 75 FR 81874 (Dec. 29, 2010).

FORM PI-1
GENERAL APPLICATION

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

TCEQ

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

I. Applicant Information		
A. Company or Other Legal Name: Channel Energy Center, LLC		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name: Mr. Patrick Blanchard		
Title: Director, EHS		
Mailing Address: 717 Texas, Suite 1000		
City: Houston	State: Texas	ZIP Code: 77002
Telephone No.: 713-830-8717	Fax No.: 713-830-8871	E-mail Address: Patrick.Blanchard@calpine.com
C. Technical Contact Name: Ms. Jan Stavinoha		
Title: Manager, EHS		
Company Name: Calpine Corporation		
Mailing Address: 717 Texas, Suite 1000		
City: Houston	State: Texas	ZIP Code: 77002
Telephone No.: 713-570-4814	Fax No.: 713-830-8871	E-mail Address: Jan.Stavinoha@calpine.com
D. Site Name: Channel Energy Center		
E. Area Name/Type of Facility: CTG/HRSG Cogeneration Unit No. 3		☑ Permanent ☐ Portable
F. Principal Company Product or Business: Electricity Generation		
Principal Standard Industrial Classification Code (SIC): 4911		
Principal North American Industry Classification System (NAICS): 221112		
G. Projected Start of Construction Date: 12/01/2012		
Projected Start of Operation Date: 06/01/2014		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 451 Light Company Road		
City/Town: Pasadena	County: Harris	ZIP Code: 77506
Latitude (nearest second): 29° 43' 08"	Longitude (nearest second): 095° 13' 55"	

I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility): HX-2690-V	
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): CN601549132	
L. Regulated Entity Number (RN): RN100213107	
II. General Information	
A. Is confidential information submitted with this application? If *Yes*, mark each **confidential** page **confidential** in large red letters at the bottom of each page.	[ ] YES [✓] NO
B. Is this application in response to an investigation or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	[ ] YES [✓] NO
C. Number of New Jobs: 0 permanent jobs; 150 temporary construction jobs	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: Mario Gallegos, Jr.	District No.: 6
Representative: Ana Hernandez Luna	District No.: 143
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): 42179, PSD-TX-955, N-021	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* Construction [✓] Flexible [ ] Multiple Plant [ ] Nonattainment [ ] Prevention of Significant Deterioration [✓] Hazardous Air Pollutant Major Source [ ] Plant-Wide Applicability Limit [ ] Other:____________________	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	[ ] YES [✓] NO

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III. Type of Permit Action Requested (continued)		
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.		☐ YES ☑ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If *No*, attach detailed information.		☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?		☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.		
List: 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.): 2084		
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved. FOP Significant Revision ☑ FOP Minor ☐ Application for an FOP Revision ☐ To Be Determined ☐ Operational Flexibility/Off-Permit Notification ☐ Streamlined Revision for GOP ☐ None ☐		

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

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V. Public Notice Information (complete if applicable)			
A. Public Notice Contact Name:			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
B. Name of the Public Place:			
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.			☐ YES ☐ NO
The public place has internet access available for the public.			☐ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits			
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.			
The Honorable:			
Mailing Address:			
City:	State:	ZIP Code:	
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 executives of the city and county, Federal Land Manager, or Indian Governing Body for the location where the facility is or will be located.			
Chief Executive:			
Mailing Address:			
City:	State:	ZIP Code:	
Name of the Federal Land Manager:			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	

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

VII. Technical Information				
B. Are any schools located within 3,000 feet of this facility?				☐ YES ☑ NO
C. Maximum Operating Schedule:				
Hours: 24	Day(s): 7	Week(s): 52	Year(s):	
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.				
E. Does this application involve any air contaminants for which a *disaster review* is required?				☐ YES ☐ NO
F. Does this application include a pollutant of concern on the *Air Pollutant Watch List (APWL)*?				☐ YES ☐ NO
VIII. State Regulatory Requirements **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment**. *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*				
A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?				☐ YES ☐ NO
B. Will emissions of significant air contaminants from the facility be measured?				☐ YES ☐ NO
C. Is the Best Available Control Technology (BACT) demonstration attached?				☐ YES ☐ NO
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?				☐ YES ☐ NO
IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*				
A. Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?				☑ YES ☐ NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?				☐ YES ☑ NO
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?				☐ YES ☑ NO

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

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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: Patrick Blanchard
Signature: Patrick Blanchard *Original Signature Required*
Date: 11-3-11

2.0 PROJECT SCOPE

2.1 INTRODUCTION

The Channel Energy Center plant currently consists of two Siemens 501F CTG/HRSG trains, one STG, and ancillary equipment. This amendment will authorize a third Siemens 501F CTG/HRSG train and ancillary equipment. The third unit, Emission Point Number (EPN) GTG/HRSG3, will consist of a CTG rated at 180 MW nominal, and a duct burner-fired heat recovery steam generator (HRSG). The maximum design rated capacity of the duct burners will be 475 million British thermal units per hour (MMBtu/hr). The CTG will be fired exclusively with pipeline-quality natural gas. The duct burners will be fired with pipeline-quality natural gas, off-gas from the adjacent refinery, or a mixture of the two (mixed gas).

The combined-cycle natural gas turbine technology proposed for the Channel Energy Center is the “FD3” turbine technology which is the current state-of-the-art electrical generating equipment for a facility of this type. The Siemens 501F turbine was chosen for the proposed third turbine at Channel Energy Center because it has the appropriate size (MW rating) needed for this site; it allows the use of common spare parts with the existing turbines at the site; and site personnel have operational and maintenance experience with that specific type of turbine.

The new CTG/HRSG will utilize an existing steam turbine generator and an existing cooling tower. A process flow diagram is included as Figure IX-C-1.

2.2 COMBUSTION TURBINE GENERATOR

The combustion turbine generator burns natural gas to rotate an electrical generator to generate electricity. The main components of a CTG consist of a compressor, combustor, turbine, and generator. The compressor pressurizes combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the turbine where the gases expand across the turbine blades, driving one or more shafts to power an electric generator. The exhaust gas exits the CTG and is routed to the HRSG for steam production.

The typical operating range will be from 60% to 100% of base load. Inlet fogging will be used to increase the mass air flow through the turbine on hot days where the ambient air is less dense. Steam injection for power augmentation may also be used to enhance power output.

2.3 HEAT RECOVERY STEAM GENERATOR

The exhaust gas from the CTG will pass though an HRSG. Heat recovered in the HRSG will be utilized to produce steam. Steam generated within the HRSG will be utilized to drive a steam turbine and associated electrical generator, or as process steam at an adjacent industrial process, or injected into the CTG for power augmentation. The HRSG will be equipped with duct burners for supplemental steam production. The duct burners will be fired with pipeline-quality natural gas, refinery gas or a combination of the two. The duct burners have a maximum heat input capacity of 475 MMBtu/hr. The exhaust gases from the unit, including emissions from the CTG and the duct burners, will exit through a stack to the atmosphere.

The normal duct burner operation will vary from 0 to 100 percent of the maximum capacity. Duct burners will be located in the HRSG prior to the selective catalytic reduction system.

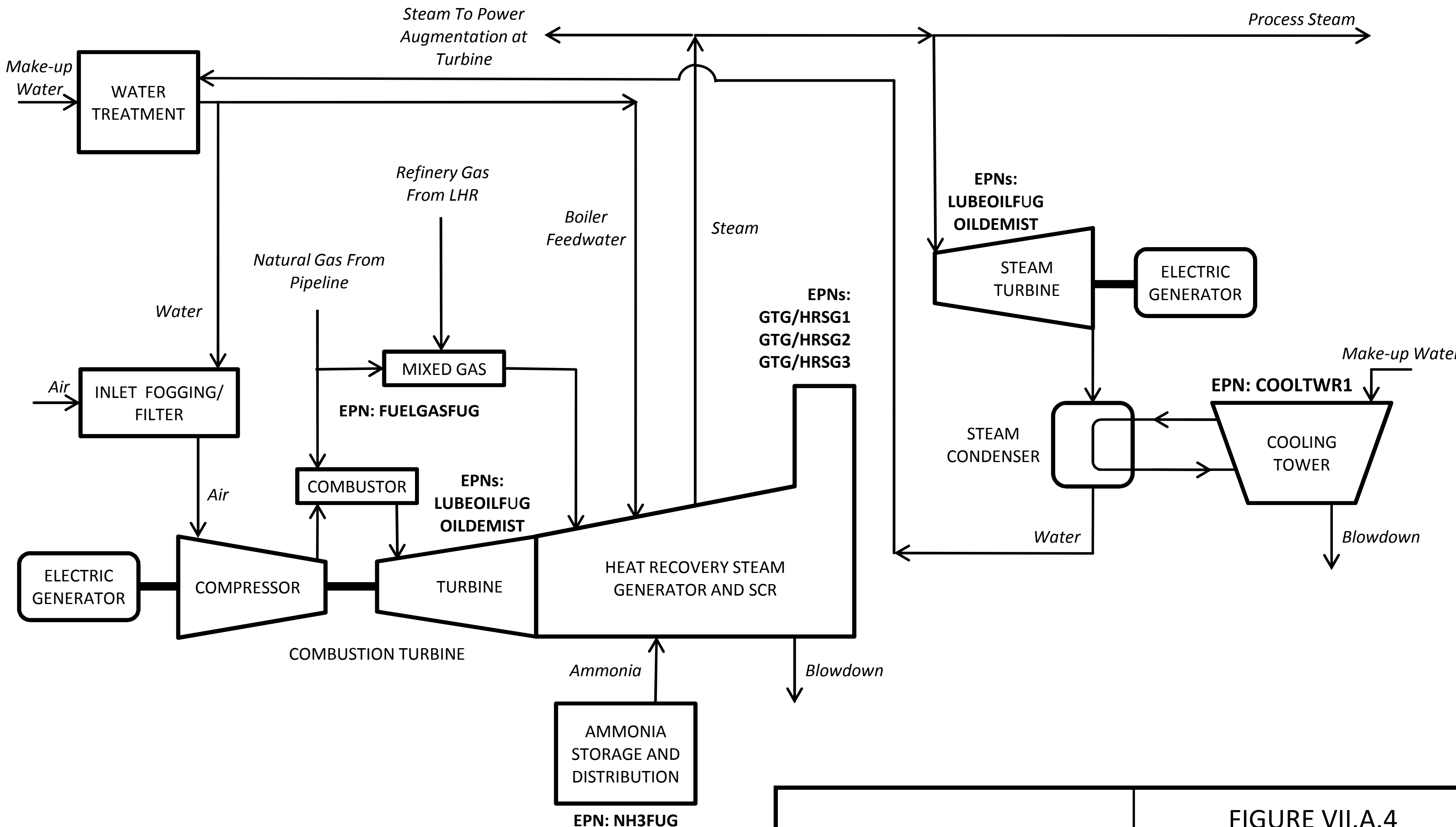
2.4 NATURAL GAS/FUEL GAS PIPING

Natural gas and refinery 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 gas piping components associated with the new CTG/HRSG unit will include emissions of methane (CH_4) and carbon dioxide (CO_2). Emissions from the natural gas piping are designated as EPN FUELGASFUG.

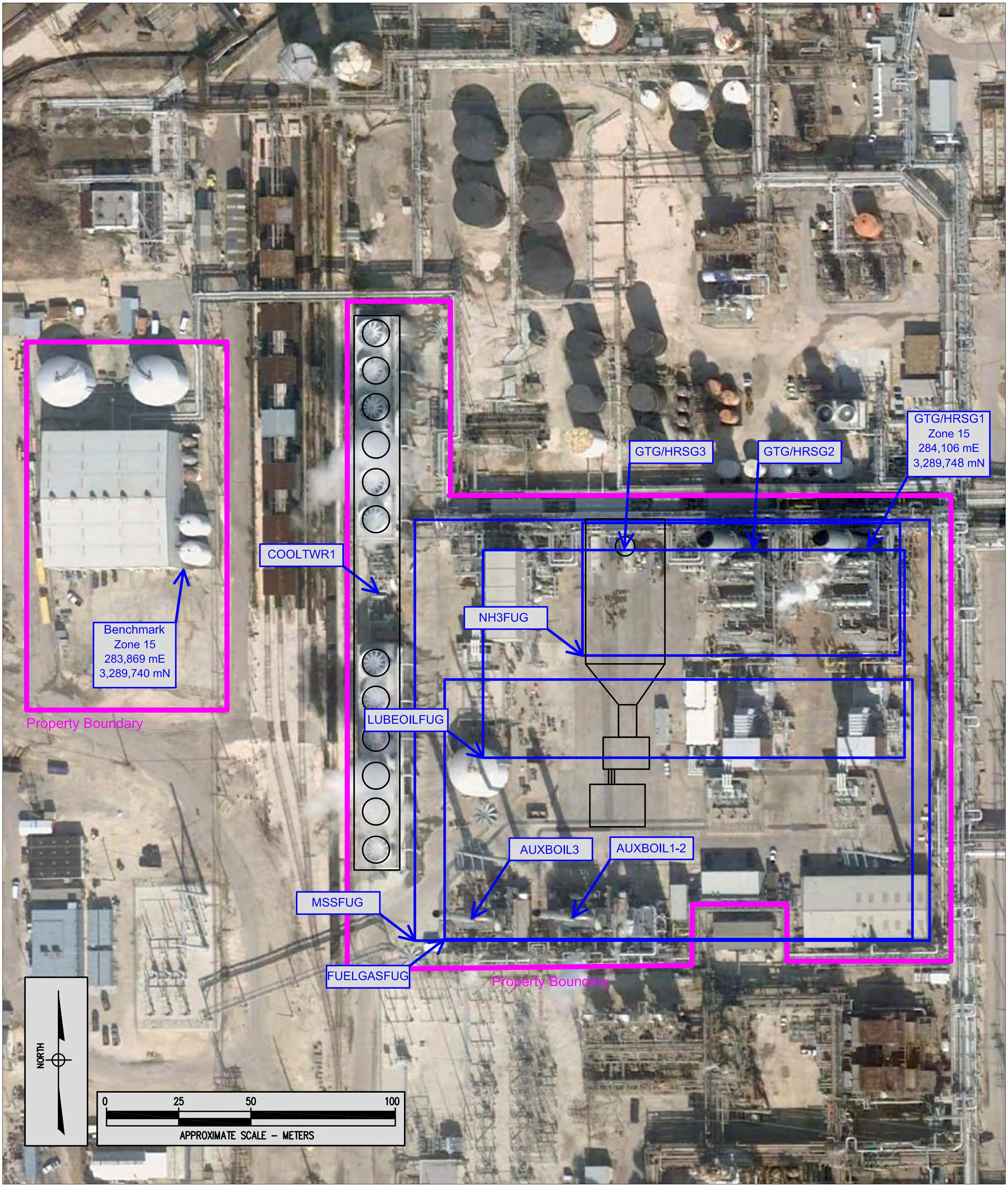
2.5 ELECTRICAL EQUIPMENT INSULATED WITH SULFUR HEXAFLUORIDE (SF_6)

The generator circuit breaker associated with the proposed unit will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable, and non-toxic synthetic 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 capacity of the generator circuit breaker associated with the proposed unit will be approximately 72 lb. In addition, a yard breaker will be added to the existing switchyard at the facility. The yard breaker will also have a capacity of approximately 72 lb of SF6.

The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. The alarm will alert operating personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of “quenching and cooling” SF_6 gas.



CHANNEL ENERGY CENTER			FIGURE VII.A.4 PROCESS FLOW DIAGRAM		
Permit Amendment Application			Filename: Fig C-1 PFD		
zephyr	Drawn by: D Castro	Checked by: L Moon	Project No.: 011337	Date: 10/25/2011	Sheet: 1 of 1



MAP SOURCE: Google Earth Pro
DATUM: NAD83

zephyr environmental corporation

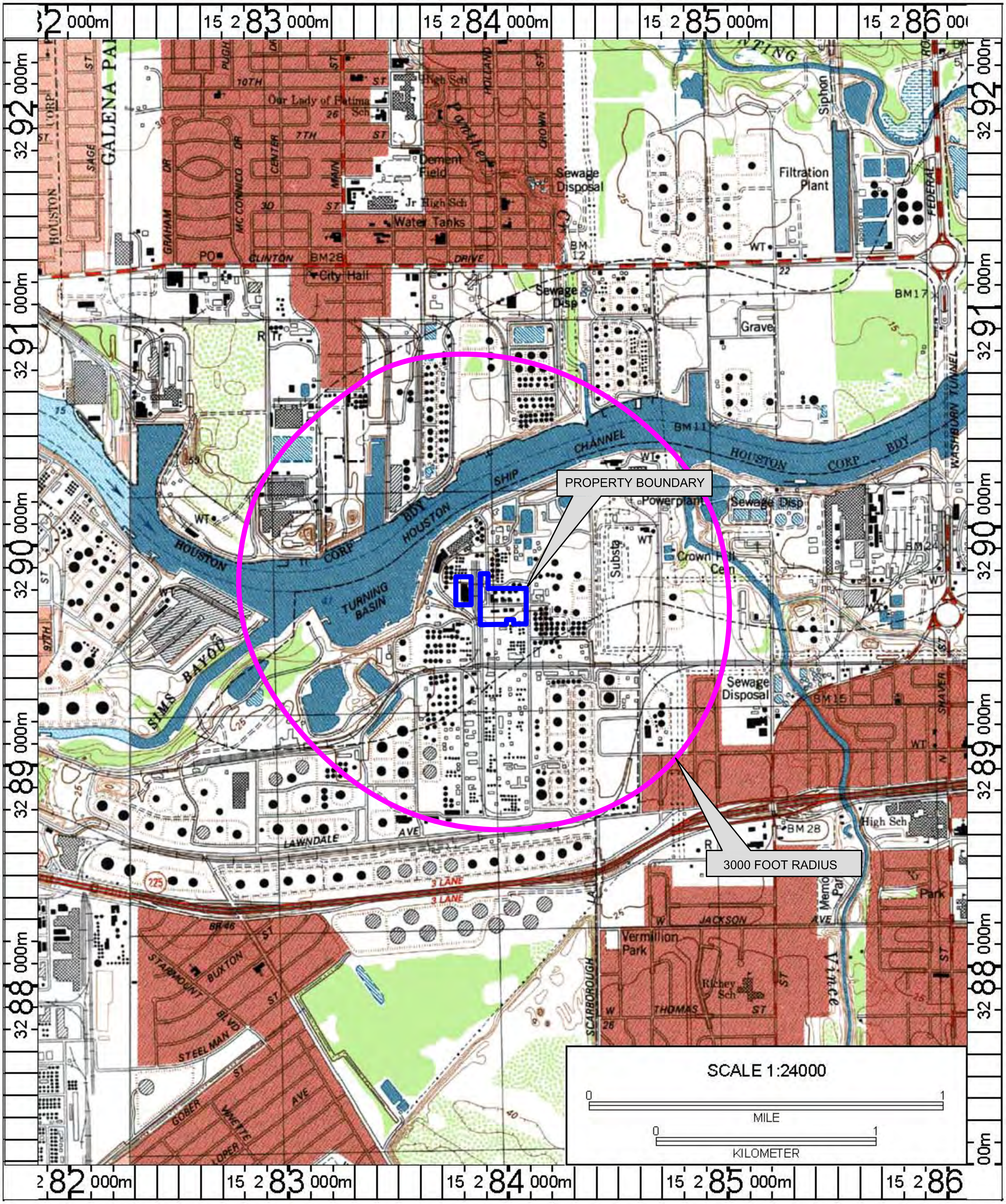
PLOT PLAN

CHANNEL ENERGY CENTER
HARRIS COUNTY, TEXAS

CHANNEL ENERGY CENTER, LLC

File Name: H:\Calpine\Channel Unit 3 Addition\Graphics\Plot Plan

Designed By:	Reviewed By:	Project No.:	Date:
R. von Czoernig	L. Moon	011337.001	9/27/11



Datum: NAD83

Digital USGS 7.5 Minute Topographic Series
—PASADENA, TX QUADRANGLE (1982)
MAP SOURCE: Terrain Navigator Pro

SITE LOCATION

AREA MAP

CHANNEL ENERGY CENTER
HARRIS COUNTY, TEXAS

CHANNEL ENERGY CENTER, LLC

File Name: H:\Calpine\10250 MSS App.\Graphics\Channel\Area Map\Area Map.dwg

Designed By:	Reviewed By:	Project No.:	Date:
R. von Czoernig	L. Moon	10250	12/17/2010

3.0 GHG EMISSION CALCULATIONS

3.1 GHG EMISSIONS FROM COMBINED CYCLE COMBUSTION TURBINE

GHG emission calculations for the combined cycle combustion turbine are calculated in accordance with the procedures in the Mandatory Greenhouse Reporting Rules, Subpart D – Electric Generation.[3] CO_2 emissions are calculated using equation G-4 of the Acid Rain Rules.[4]

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

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, 1040 scf/MMBtu for natural gas.

H = Annual heat input in MMBtu.

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

Emissions of CH_4 and nitrous oxide (N_2O) are calculated using the emission factors (kg/MMBtu) for natural gas combustion from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[5] The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.

3.2 GHG EMISSIONS FROM NATURAL GAS/FUEL GAS PIPING FUGITIVES AND NATURAL GAS/FUEL 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.[6] 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 refinery gas is variable, the concentrations of CH_4 and CO_2 from the typical natural gas analysis are used as a worst case estimate. The

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[3] 40 C.F.R. 98, Subpart D – *Electricity Generation*

[4] 40 C.F.R. 75, Appendix G – *Determination of CO_2 Emissions*

[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] *Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production*, 40 C.F.R. Pt. 98, Subpt. W, Tbl. W-1A.

global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.[7]

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.

3.3 GHG EMISSIONS FROM ELECTRICAL EQUIPMENT INSULATED WITH SF_6

SF_6 emissions from the new generator circuit breaker and yard breaker associated with the proposed unit 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 Mandatory Greenhouse Gas Reporting Rules.[8]

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

[8] *Id.*

Table 3-1

Annual GHG Emission Calculations - New Combined Cycle Combustion Turbine

Channel Energy Center, LLC

Annual GHG Emissions Contribution From Natural Gas Fired CTG/HRSG3

EPN	Annual Heat Input[1] (MMBtu/hr)	Pollutant	Emission Factor (kg/MMBtu)[2]	GHG Mass Emissions[3] (tpy)	Global Warming Potential[4]	CO_2e (tpy)
CTG/HRSG3	16,866,859.5	CO_2		1,002,373	1	1,002,373
		CH_4	1.0E-03	19	21	390
		N_2O	1.0E-04	2	310	576
			Totals	**1,002,394**		**1,003,340**

Note

1. The following annual firing rate Information is from Tables A-3A and A-4A, in Appendix A of the PSD application submitted to TCEQ on 11/03/2011.

Operating Mode	CTG Data Case Number	Annual Operating Hours hr/yr	Turbine Heat Input MMBtu/hr	Duct Burner Heat Input MMBtu/hr	Total Hourly Heat Input MMBtu/hr	Total Annual Heat Input MMBtu/yr
Base Load, 70 °F Ambient, Avg Duct Burner Firing	9b	6760	1,827.5	0	1,827.5	12,353,614.5
Base Load, 90 °F Ambient, Peak Duct Burner Firing	4b	1500	1,751.7	475	2,226.7	3,340,042.8
Base Load, 90 °F Ambient, Peak Duct Burner Firing, Power Augmentation	2b	500	1,871.4	475	2,346.4	1,173,202.3
		8760				**16,866,859.5**

2. CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

3. CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4

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

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

Fc = 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/lbmole*

4. Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

Table 3-2

Startup GHG Emission Calculations - New Combined Cycle Combustion Turbine

Channel Energy Center, LLC

Startup/Shutdown Hourly GHG Emissions From Natural Gas Fired CTG/HRSG3

EPN	Heat Input During Startup[1, 2] (MMBtu/hr)	Pollutant	Emission Factor (kg/MMBtu)[3]	GHG Mass Emissions[4] (ton/hr)	Global Warming Potential[5]	CO_2e (ton/hr)
CTG/HRSG3	1,163.9	CO_2		69	1	69
		CH_4	1.0E-03	0.0013	21	0.0269
		N_2O	1.0E-04	0.0001	310	0.0398
			Totals	**69**		**69**

Note

1. *The following hourly firing rates Information is from Table A-3H, in Appendix A of the PSD application submitted to TCEQ on 11/03/2011.*

	Operating Mode	CTG Data Case Number	Turbine Heat Input MMBtu/hr	Duct Burner Heat Input MMBtu/hr	Total Hourly Heat Input MMBtu/hr
Maximum Hourly Heat Input	Base Load, 20 °F Ambient, Max Duct Burner Firing	13b	2,016.5	452	2,468.5
Maximum Hourly Heat Input During Startup	60% Load, 90 °F Ambient, no Duct Burner Firing	7	1,163.9	0	1,163.9

2. Startup Emission Basis: 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 60% load. Since GHG emissions are proportional to fuel consumption, high GHG emissions during a startup occurs at the point of highest fuel comsumption (approximately 60% load).
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*

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

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

Fc = 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/lbmole

5. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Table 3-3
GHG Emission Calculations - Natural Gas/Fuel Gas Piping
Channel Energy Center, LLC

GHG Emissions From New Natural Gas/Fuel Gas Piping Components Associated with New Turbine 3

EPN	Source Type	Fluid State	Count	Emission Factor[1] scf/hr/comp	CO_2[2,3] (tpy)	Methane[2,3] (tpy)	Total (tpy)
Natural Gas Piping	Valves	Gas/Vapor	60	0.123	0.05	1.27	
	Flanges	Gas/Vapor	240	0.017	0.03	0.70	
	Relief Valves	Gas/Vapor	8	0.196	0.01043	0.26986	
	Sampling Connections [5]	Gas/Vapor	18	0.123	0.01472	0.38104	
Fuel Gas Piping	Valves	Gas/Vapor	148	0.123	0.12	3.13	
	Flanges	Gas/Vapor	162	0.017	0.02	0.47	
	Relief Valves	Gas/Vapor	0	0.196	0.00	0.00	
	Sampling Connections [5]	Gas/Vapor	58	0.123	0.05	1.23	
GHG Mass-Based Emissions					0.29	7.46	***7.7***
Global Warming Potential[4]					1	21	
CO_2e Emissions					0.29	156.62	***156.9***

Note

1. *Emission factors from Table W-1A of 40 CFR 98 Mandatory Greenhouse Gas Reporting*
2. *CO_2 and CH_4 content from a typical natural gas analysis is obtained from Table A-2A, Appendix A of the PSD application submitted to TCEQ on 11/03/2011.*

   CO_2 emissions based on vol% of CO_2 in natural gas 1.33%

   CH_4 emissions based on vol% of CH_4 in natural gas 94.44%

3 *Since the CH_4 content of refinery gas is highly variable, the concentrations from a typical natural gas analysis are used as a worst case estimate.*

4. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
5. *No emission factor in Table W-1a so conservatively used valve emission factor.*

Example calculation:

60 valve	0.123 scf gas	0.0133 scf CO_2	lbmole	44.01 lb CO_2	8760 hr	ton =	0.05	ton/yr
	hr * valve	scf gas	385.5 scf	lbmole	yr	2000 lb		

TABLE 3-4
Gaseous Fuel Venting During Turbine Shutdown/Maintenance and Small Equipment and Fugitive Component Repair/Replacement
Channel Energy Center, LLC

Location	Initial Conditions[1]			Final Conditions[1]			CO_2[4]	CH_4[4]	Total
	Volume[2] (ft^3)	Press. (psig)	Temp. (°F)	Press. (psig)	Temp. (°F)	Volume[3] (scf)	Annual (tpy)	Annual (tpy)	Annual (tpy)
Turbine Fuel Line Shutdown/Maintenance	955	**50**	**50**	0	68	4,397	0.0033	0.09	
Small Equipment/Fugitive Component Repair/Replacement	6.7	**50**	**50**	0	68	31	0.00002	0.00060	
GHG Mass-Based Emissions							0.0034	0.0870	0.0904
Global Warming Potential[5]							1	21	
CO_2e Emissions							0.0034	1.8269	1.8303

1. Information for these calculations is obtained from Table A-14, in Appendix A of the PSD application submitted to TCEQ on 11/03/2011.
2. 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
3. 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: $Z = 0.9994 - 0.0002P + 3E\text{-}08P^2$.
4. *CO_2 and CH_4 content from a typical natural gas analysis is obtained from Table A-2A, Appendix A of the PSD application submitted to TCEQ on 11/03/2011.*
   CO_2 emissions based on vol% of CO_2 in natural gas 1.33%
   CH_4 emissions based on vol% of CH_4 in natural gas 94.4%
5. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Example calculation:

4,397 scf Nat Gas	0.0133 scf CO_2	lbmole	44.01 lb CO_2	ton =	=	0.0033	ton/yr CO_2
yr	scf Nat Gas	385.5 scf	lbmole	2000 lb			

Table 3-5
GHG Emission Calculations - Electrical Equipment Insulated With SF_6
Channel Energy Center, LLC

Assumptions

New insulated generator circuit breaker SF_6 capacity	72	lb
New insulated yard circuit breaker SF_6 capacity	72	lb
Estimated annual SF_6 leak rate	0.5%	by weight
Estimated annual SF_6 mass emission rate	0.00036	ton/yr
Global Warming Potential[1]	23,900	
Estimated annual CO_2e emission rate	8.6	ton/yr

Note

1. Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

4.0 PREVENTION OF SIGNIFICANT DETERIORATION APPLICABILITY

In the EPA guidance document *PSD and Title V Permitting Guidance for Greenhouse Gases,* the following PSD Applicability Test was provided for Step 1 of the PSD Tailoring rule for existing sources:

EPA Tailoring Rule Step 1 - PSD Applicability Test for GHGs

PSD applies to the GHG emissions from a proposed modification to an existing major source if the following is true:

- The emissions increase ***and*** the **net** emissions increase of GHGs from the modification would be equal to or greater than 75,000 TPY on a CO_2e basis ***and*** greater than zero TPY on a mass basis.

Since the project emissions increase of GHG is greater than 75,000 ton/yr of CO_2e and greater than zero ton/yr on a mass basis, and there are no contemporaneous emission changes of GHG and CO_2e, PSD is triggered for GHG emissions. The emissions netting analysis is documented on the attached TCEQ PSD netting tables: Table 1F and Table 2F. Also included in Appendix A is the "The GHG PSD APPLICABILITY FLOWCHART – EXISTING SOURCES from the *PSD and Title V Permitting Guidance for Greenhouse Gases".*

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TCEQ PSD NETTING TABLES

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TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.:	42179, PSD-TX-955, and N-021	Application Submittal Date:	11/03/2011
Company	Channel Energy Center, L.P.		
RN:	RN100213107	Facility Location:	451 Light Company Road, Pasadena, Texas
City	Pasadena	County:	Harris
Permit Unit I.D.:	GTG/HRSG3	Permit Name:	Channel Energy Center
Permit Activity:	☐ New Major Source	☑ Modification	
Project or Process Description:	Authorize a new turbine unit with heat recovery steam generator		

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					> 100,000	> 100,000
Proposed project increases (tpy from 2F)[3]						1,002,402	1,003,508
Is the existing site a major source? If not, is the project a major source by itself? (yes or no)	Yes						
If site is major, is project increase significant? (yes or no)						Yes	Yes
If netting required, estimated start of construction:		6/1/12					
5 years prior to start of construction:		6/2/07	Contemporaneous				
estimated start of operation:		6/1/14	Period				
Net contemporaneous change, including proposed project, from Table 3F (tpy)						Note 4	Note 4
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.

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

Signature	Title	Date
[signature]	Director - EHS	11-3-11

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TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	**GHG**	**Permit:**	**42179, PSD-TX-955, and N-021**
Baseline Period:	**Jan-09**	**to**	**Dec-10**

Affected or Modified Facilities[2]			Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions[5]	Projected Actual Emissions	Difference (A-B)[6]	Correction[7]	Project Increase[8]
	FIN	EPN								
1	CTG/HRSG3	CTG/HRSG3	42179	0	0	1,002,394		1,002,394		1,002,394
2	FUELGASFUG	FUELGASFUG	42179	0	0	7.7		7.7		7.7
3	SF6	N/A	42179	0	0	0.0004		0.0004		0.0004
4	MSS-Unit 3	MSSFUG	45642	0	0	0.09		0.09		0.09
									Total	1,002,402

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.

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TABLE 2F
PROJECT EMISSION INCREASE

Pollutant(1):	**CO2e**	**Permit:**	**42179, PSD-TX-955, and N-021**
Baseline Period:	**Jan-09**	**to**	**Dec-10**

Affected or Modified Facilities(2)			Permit No.	Actual Emissions(3)	A Baseline Emissions(4)	B Proposed Emissions(5)	Projected Actual Emissions	Difference (A-B)(6)	Correction(7)	Project Increase(8)
	FIN	EPN								
1	CTG/HRSG3	CTG/HRSG3	42179	0	0	1,003,340		1,003,340		1,003,340
2	FUELGASFUG	FUELGASFUG	42179	0	0	157		157		157
3	SF6	N/A	42179	0	0	9		9		9
4	MSS-Unit 3	MSSFUG	42179	0	0	1.83		1.8		1.8
									Total	1,003,508

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)

The PSD rules define BACT as:

> *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.[9]

In the EPA guidance document titled *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA recommended the use of the Agency's five-step "top-down" BACT process to determine BACT for GHGs.[10] 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.

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[9] 40 C.F.R. § 52.21(b)(12.)

[10] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, p. 18 (Nov. 2010).

Step 5: Select the BACT.

5.1 BACT FOR THE COMBINED CYCLE COMBUSTION TURBINE

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 F-Class natural gas fired combined cycle unit operating under optimal conditions has a baseload efficiency of approximately 50% (HHV).

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

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

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

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

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

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. For cogeneration units such as the proposed unit, duct burner firing serves two purposes: (1) additional power generation capacity during periods of high electrical demand, and (2) additional steam generation capacity during periods of high steam demand from the host facility.

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

Heat Exchanger Design Considerations

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 F-Class combustion turbines, these temperatures can approach 1,200°F. HRSGs are designed to maximize the conversion of the waste heat to steam. One aspect of the HRSG design in maximizing this waste heat conversion is the use of insulation. Insulation minimizes heat loss to the 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 Plant-wide 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 temperatures. For the F-Class combustion turbine based combined cycle, the fuel gas is generally heated with high temperature water from the HRSG. This improves the efficiency of the combustion turbine.
- **Drain operation** – Drains are required to allow for draining the equipment for maintenance (i.e., maintenance drains), and also to allow condensate to be removed from the steam piping and drains for operation (i.e., operation drains). Operation drains are generally controlled to minimize the loss of energy from the cycle. This is accomplished by closing the drains as soon as the appropriate steam conditions are achieved.
- **Multiple combustion turbine/HRSG trains** – Multiple combustion turbine/HRSG trains help with part-load operation. The multiple trains allow the unit to achieve higher overall plant part-load efficiency by shutting down trains operating at less efficient part-load conditions and ramping up the remaining train(s) to high-efficiency full-load operation.
- **Boiler feed pump fluid drives** – The boiler feed pumps are used as the means to impart high pressure on the working fluid. The pumps require considerable power. To minimize the power consumption at part-loads, the use of fluid drives or variable-frequency drives can be employed. For this project, fluid drives are being used to minimize power consumption 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 add-on technologies as possible ways to capture GHG emissions that are emitted from natural gas combustion in the proposed project's CTG/HRSG unit and to prevent them from entering the atmosphere. These emerging carbon capture and storage (CCS) technologies generally consist of processes that separate CO_2 from combustion process flue gas, and then inject it into 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:

> …In the future, emerging R&D will provide numerous cost-effective technologies for capturing CO_2 from power plants. At present, however, state-of-the-art technologies for existing power plants are essentially limited to amine absorbents. Such amines are used extensively in the petroleum refining and natural gas processing industries… Amine solvents are effective at absorbing CO_2 from power plant exhaust streams—about 90 percent removal—but the highly energy-intensive process of regenerating the solvents decreases plant electricity output…[11]

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 (15-25 pounds per square inch absolute [psia]), which dictates that a high volume of gas be treated.
> - Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes.
> - Compressing captured or separated CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall power plant system…[12]

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

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[11] DOE-NETL, *Carbon Sequestration: FAQ Information Portal*, http://extsearch1.netl.doe.gov/search?q=cache:e0yvzjAh22cJ:www.netl.doe.gov/technologies/carbon_seq/FAQs/tech-status.html+emerging+R%26D&access=p&output=xml_no_dtd&ie=UTF-8&client=default_frontend&site=default_collection&proxystylesheet=default_frontend&oe=ISO-8859-1 (last visited Aug. 8, 2011).

[12] *Id.*

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, 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…"[13]

5.1.2 Step 2: Eliminate Technically Infeasible Options

In this section, Channel Energy Center addresses the potential feasibility of implementing CCS technology as BACT for GHG emissions from the proposed project's gas turbine/HRSG train. Each component of CCS technology (i.e., capture and compression, transport, and storage) is discussed separately.

5.1.2.1 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:

> "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."[14]

5.1.2.2 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 pipeline was constructed are delineated on

[13] DOE-NETL, ***Carbon Sequestration:*** *Geologic Storage Focus Area,* http://www.netl.doe.gov/technologies/carbon_seq/corerd/storage.html (last visited Aug.8, 2011)

[14] *Report of the Interagency Task Force on Carbon Capture and Storage* at 50 (Aug. 2010).

the map found at the end of Section 5.[15] 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) will be the lesser of the following:

- The distance to the closest site with recognized potential for some geological storage of CO_2, which is an enhanced oil recovery (EOR) reservoir site located within 15 miles of the proposed project; or
- The distance to a CO_2 pipeline that Denbury Green Pipeline-Texas is currently constructing within 10 miles of the project site for the purpose of providing CO_2 to support various EOR operations in Southeast Texas beginning in late 2013.

However, none of the Southeast Texas EOR reservoir or other geologic formation sites have yet been technically demonstrated for large-scale, long-term CO_2 storage.

In comparison, the closest site that is currently being field-tested to demonstrate its capacity for large-scale geological storage of CO_2 is the Southeast Regional Carbon Sequestration Partnership's (SECARB) Cranfield test site, which is located in Adams and Franklin Counties, Mississippi over 260 miles away (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 very long and sizable pipeline would need to be constructed to transport the large volume of high-pressure CO_2 from the plant to the storage facility, thereby rendering implementation of a CO_2 transport system infeasible.

5.1.2.3 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 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,

[15] 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 Aug. 8, 2011).

- 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,[16] and
- Potential effects on wildlife.

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

Based on the reasons provided above, Channel Energy Center 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, Channel Energy Center has estimated such costs. Those cost estimates are presented on Table 5-1 at the end of Section 5.

5.1.3 Step 3: Rank Remaining Control Technologies

As documented above, implementation of CCS technology is currently infeasible, leaving energy efficiency measures as the only technically feasible emission control options. As all of the energy efficiency related processes, practices, and designs discussed in Section 5.1.1 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 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. Because the CCS add-on control option discussed in Section 5.1.2 was determined to be technically infeasible, an examination of the energy, environmental, and economic impacts of that option is not necessary for this application. However, at the request of EPA Region 6, Channel Energy Center is including estimated costs for implementation of CCS.

[16] *Id.*

5.1.5 Step 5: Select BACT

Channel Energy Center proposes as BACT for this project, the following energy efficiency processes, practices, and designs for the proposed combined cycle combustion turbine:

- 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
  - Instrumentation and controls
- HRSG Energy Efficiency Processes, Practices, and Designs
  - Efficient heat exchanger design
  - Insulation of HRSG
  - Minimizing Fouling of heat exchange surfaces
  - Minimizing vented steam and repair of steam leaks
- Plant-wide Energy Efficiency Processes, Practices, and Designs
  - Fuel gas preheating
  - Drain operation
  - Multiple combustion turbine/HRSG trains
  - Boiler feed pump fluid drive design

To determine the appropriate heat-input efficiency limit, Channel Energy Center started with the turbine's design base load net 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 net heat rate for the Siemens 501F-FD3 turbine is 6,852 Btu/kWhr (HHV) without duct firing and 6,970 Btu/kWhr (HHV) with duct firing. Note that this rate reflects the facility's "net" power production, meaning the denominator is the amount of power provided to the grid; it does not reflect the total amount of energy produced by the plant, which also includes auxiliary load consumed by operation of the plant. To be consistent with other recent GHG BACT determinations, the net heat rate without duct firing is used to calculate the heat-input efficiency limit.

During periods when some or all of the generated steam is sold to the neighboring facility rather than sent to the on-site steam turbine, the energy efficiency of the equipment utilizing the steam at the neighboring facility may be different than the efficiency of Channel Energy Center's existing steam turbine. Therefore, for purposes of the heat input limit for this application, the heat rate is calculated assuming that all steam generated in the heat recovery steam generator is used to generate electricity in the existing on-site steam turbine.

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% performance margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls.
- A 3% degradation margin reflecting the variability in operation of auxiliary plant equipment due to use over time.

As a result of these adjustments, Channel Energy Center is proposing a BACT net heat rate for the Project of 7,730 Btu/kWh (HHV), corrected to ISO conditions of:

- Ambient Dry Bulb Temperature: 59ºF
- Ambient Relative Humidity: 60%
- Barometric Pressure: 14.69 psia
- Fuel Lower Heating Value: 20,647 Btu/lb
- Fuel HHV/LHV Ratio: 1.1086

This heat rate limit is equivalent to an output based GHG BACT limit of 0.460 ton CO_2e/MWhr (net) BACT. The calculation of the net heat rate and the equivalent ton CO_2e/MWhr is provided on Table 5-2 of this application.

Channel Energy Center performed a search of the EPA's RACT/BACT/LAER Clearinghouse for natural gas fired combustion turbine generators and found no entries which address BACT for GHG emissions. Although not listed in the RACT/BACT/LAER Clearinghouse, a GHG BACT analysis was performed by the following natural gas fired power generation facilities: Russell City Energy Center, Palmdale Hybrid Power Plant, Lower Colorado River Authority Ferguson Plant, Cricket Valley Energy Center, and Pioneer Valley Energy Center. A discussion of the Channel Energy Center's proposed BACT as compared to those projects is provided below:

Palmdale Hybrid Power Project

The application for the Palmdale Hybrid Power Project (PHPP) was submitted in May 2011 and a draft permit was issued by the Antelope Valley Air Quality Management District in August 2011. The PHPP application proposed the construction of two natural-gas-fired GE 7FA combustion turbine generators, with 500 MMBtu/hr duct fired heat recovery steam generators, and one steam turbine generator to be located in Palmdale, California. The project includes a 50 MW solar thermal generator component. The draft permit listed a GHG BACT limit of 774 lb CO_2/MW-hr source-wide net output and 117 lb CO_2/MMBtu heat input, for each GEN1/DB1 and GEN2/DB2.

The application submitted by PHPP represented as BACT, a heat rate of 6,970 Btu/kWh, based on the higher heating value (HHV) of natural gas with two CTGs operating at 100% with no solar input and with no duct firing. A CO_2 emission rate of 0.408 short tons of CO_2/MW-hr was derived from the heat rate of 6,970 Btu/Kw-hr based on a CO_2 emission factor of 53.06 kg CO_2/MMBtu. 0.408 short tons of CO_2/MW-hr equates to 816 lb CO_2/MW-hr.

The BACT representations in the draft permit and the application cannot be directly compared to the representations for the Channel Energy Center for the following reasons:

1. The permit limit of 774 lb CO_2/MW-hr does not correspond to the representations in the PHPP application. PHPP represented a CO_2 emission rate of 0.408 short tons CO_2/MW-hr (816 lb CO_2/MW-hr) for the two combustion turbines, without duct burner firing. The basis of the 774 lb CO_2/MWhr permit limit is unclear.
2. The permit limit of 117 lb CO_2/MMBtu heat input is simply a conversion of the 53.06 kg CO_2/MMBtu emission factor which was used in the application, and is not based on the proposed energy efficiency of the power plant. The Channel Energy Center application uses the average emission factor for natural gas combustion provided in the Greenhouse Gas Reporting Rules of 53.02 kg CO_2/MMBtu.
3. The PHPP application does not state whether the 6,970 Btu/kWh heat rate represented as BACT, is on a gross electrical output basis or a net electrical output basis. The net electrical output accounts for the electricity used internally at the plant. If based on gross output, the heat rate would be lower than if based on a net electrical output basis. The heat rate proposed as BACT for Channel Energy Center is based on a net electrical output basis.
4. It appears that the represented heat rate of 6,970 Btu/kW-hr in the PHPP application is the “design” basis for the plant since there was no discussion of factoring in any design margins, performance margins, or degradation margins into the represented heat rate. For comparison purposes, the “design” heat rate for the Channel Energy Center combustion turbine, before factoring in design margins, performance margins, and degradation margins is 6,852 Btu/kW-hr (HHV) on a net output basis, without duct firing.

Lower Colorado River Authority Ferguson Plant

The application for the LCRA Ferguson Plant was submitted in March 2011 and a draft permit was issued September 28, 2011. The application included two natural-gas-fired GE 7FA combustion turbines, heat recovery steam generators without no additional duct firing, and one steam turbine generator to be located in Marble Falls, Texas. The draft permit included BACT limits of 0.459 ton CO_2/MWh (net) on a 365 day rolling average and an average net heat rate of 7,720 Btu/kWh (HHV) on a 365 day rolling average.

For comparison purposes, the Channel Energy Center application proposes a heat input rate of 7,730 Btu/kWh (HHV, net basis), which accounts for design margins, performance margins, and degradation margins and an emission rate of 0.459 ton CO_2/MW-hr (net) [0.460 ton CO_2e/MW-hr (net)].

Cricket Valley Energy Center

The Cricket Valley Energy Center (CVEC) air permit application proposed the construction of 3 natural-gas-fired GE 7FA combustion turbines, with 596.8 MMBtu/hr duct fired heat recovery steam generators, and three steam turbine generators to be located in Dover, New York. The CVEC application represented that the GE 7FA turbines operating in combined cycle mode have a design base heat rate of 6,742 Btu/kW-hr at ISO conditions with no duct firing (based on net output). Based upon the design efficiency, and adding a reasonable margin of compliance, CVEC proposed a limit of 7,605 Btu/kW-hr (ISO conditions without duct firing) as BACT for the proposed project.

For comparison purposes, the Channel Energy Center application proposes a heat input rate of 7,730 Btu/kWh (HHV, net basis), which accounts for design margins, performance margins, and degradation margins, which is within 1.6% of the proposed CVEC proposed limit. The efficiencies from two similarly sized combined cycle electric generating units will not be identical due to differences in the properties and variability of the natural gas; the geographic location - higher combustion turbine efficiencies are achieved at lower elevations and at cooler ambient temperatures due to denser ambient air; differences in combustion turbine designs, heat recovery steam generator designs and steam turbine designs; and electric generating unit load generation flexibility requirements - operating an electric generating unit as a baseload unit is more efficient than operating as a load cycling unit to respond to fluctuations in customer electricity or steam demands.

Pioneer Valley Energy Center

The Pioneer Valley Energy Center (PVEC) air permit application proposed the construction of a 431 MW natural-gas-fired combined cycle turbine generator to be located in Westfield, Massachusetts. The manufacturer of the turbine was not specified in the application. PVEC represented a design net heat rate of the Project's power island of 5,948 Btu/kW-hr based on the annual average temperature in the project area and the use of natural gas fuel with a lower heating value of 925 Btu per cubic foot. PVEC proposed a BACT heat rate for the Project of 6,840 Btu/kWh based on a 3% design margin, 6% performance margin, and 6% degradation margin. Note that the represented design heat rate and the proposed BACT heat rate are based on the lower heating value of natural gas. The lower heating value of natural is typically about 10% lower than the gross heating value of natural, meaning that a heat rate calculated based on the lower heating value of natural gas would be about 10% lower than a heating value based on the gross heating value of natural gas. There is not a represented heat rate based on the higher heating value of natural gas for a direct comparison the Channel Energy Center proposed heat rate. Also, the design net heat rate is based on the annual average temperature in the project area rather than ISO conditions.

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

One alternative considered in this analysis is to substitute another, non-greenhouse-gas substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NTIS) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6.*[17]

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

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 highest ranked 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-greenhouse-gas 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, Channel Energy Center concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection would be the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers.[19] The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will bring potential

[17] 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.

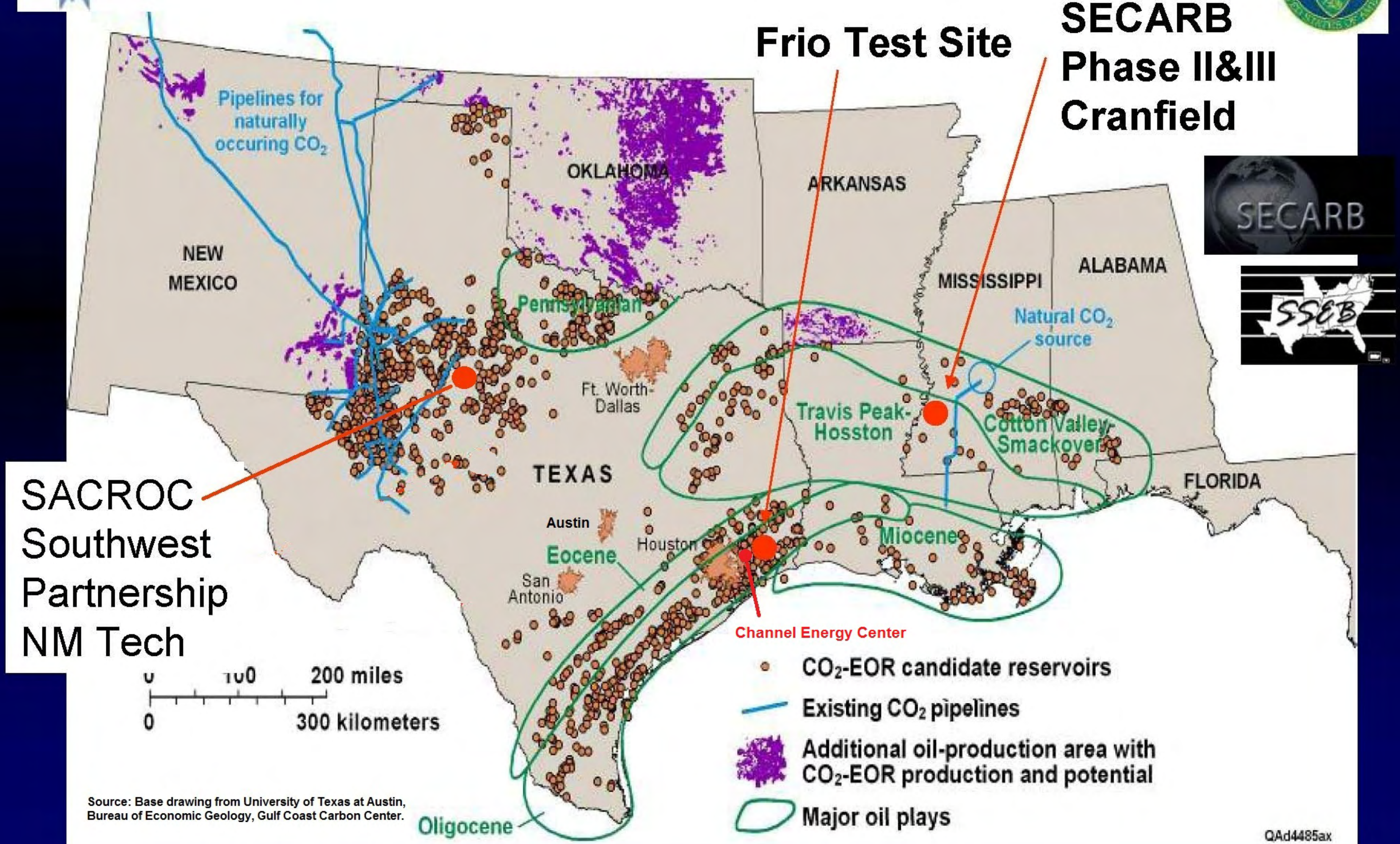
[18] *Id.* at 28 – 29.

[19] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*.

fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF_6 gas.

Channel Energy Center will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use.[20] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

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



Frio Test Site
SECARB
Phase II&III
Cranfield
SECARB
SSEB
Pipelines for
naturally
occuring CO_2
OKLAHOMA
ARKANSAS
NEW
MEXICO
MISSISSIPPI
ALABAMA
Pennsylvanian
Natural CO_2
source
Ft. Worth-
Dallas
Travis Peak-
Hosston
Cotton Valley-
Smackover
TEXAS
FLORIDA
SACROC
Southwest
Partnership
NM Tech
Austin
Houston
Miocene
Eocene
San
Antonio
Channel Energy Center
0 100 200 miles
0 300 kilometers
CO_2-EOR candidate reservoirs
Existing CO_2 pipelines
Additional oil-production area with
CO_2-EOR production and potential
Major oil plays
Source: Base drawing from University of Texas at Austin,
Bureau of Economic Geology, Gulf Coast Carbon Center.
Oligocene
QAd4485ax

Table 5-1
Range of Approximate Annual Costs for Installation and Operation of Capture, Transport, and Storage Systems for Control of CO_2 Emissions from Proposed Electric Generating Unit 3 at Channel Energy Center, Harris County, Texas

Carbon Capture and Storage (CCS) Component System	Factors for Approximate Costs for CCS Systems	Annual System CO_2 Throughput (tons of CO_2 captured, transported, and stored) [1]	Pipeline Length for CO_2 Transport System (km CO_2 transported) [5]	Range of Approximate Annual Costs for CCS Systems ($)
Post-Combustion CO_2 Capture and Compression System				
Minimum Cost	$44.11 / ton of CO_2 avoided [2]	956,349		$42,184,554
Maximum Cost	$103.42 / ton of CO_2 avoided [3]	956,349		$98,904,711
Average Cost	$73.76 / ton of CO_2 avoided [4]	956,349		$70,544,632
CO_2 Transport System				
Minimum Cost	$0.91 / ton of CO_2 transported per 100 km [3]	956,349	24	$209,562
Maximum Cost	$2.72 / ton of CO_2 transported per 100 km [3]	956,349	24	$628,685
Average Cost	$1.81 / ton of CO_2 transported per 100 km [4]	956,349	24	$419,123
CO_2 Storage System				
Minimum Cost	$0.51 / ton of CO_2 stored [3, 6]	956,349		$485,848
Maximum Cost	$18.14 / ton of CO_2 stored [3, 6]	956,349		$17,351,704
Average Cost	$9.33 / ton of CO_2 stored [4]	956,349		$8,918,776
Total Cost for CO_2 Capture, Transport, and Storage Systems				
Minimum Cost	$44.84 / ton of CO_2 removed	956,349		$42,879,964
Maximum Cost	$122.22 / ton of CO_2 removed	956,349		$116,885,099
Average Cost	$83.53 / ton of CO_2 removed [4]	956,349		$79,882,531

[1] Assumes that a capture system would be able to capture 90% of the total CO_2 emissions generated by the power plant's gas turbines.

[2] This cost factor is the minimum found for implementation/operation of CO_2 capture systems within the cost-related information reviewed for CCS technology. The factor is from the on the "Properties" spreadsheet of the *Greenhouse Gas Mitigation Strategies Database* (Apr. 2010) (http://ghg.ie.unc.edu:8080/GHGMDB/#data), which was obtained through the EPA GHG web site (http://www.epa.gov/nsr/ghgpermitting.html). The factor is based on the increased cost of electricity (COE; in $/MW-h) resulting from implementation and operation at a CO_2 capture system on a natural gas-fired combined cycle power plant. The factor accounts for annualized capital costs, fixed operating costs, variable operating costs, and fuel costs.

[3] These cost factors are from *Report of the Interagency Task Force on Carbon Capture and Storage*, pp.33, 34, 37, and 44 (Aug. 2010) (http://www.epa.gov/climatechange/policy/ccs_task_force.html). The factors from the report in the form of $/tonne of CO_2 avoided, transported, or stored and have been converted to $/ton. Per the report, the factors are based on the increased cost of electricity (COE; in $/kW-h) of an "energy-generating system, including all the costs over its lifetime: initial investment, operations and maintenance, cost of fuel, and cost of capital".

[4] The average cost factors were calculated as the arithmetic mean of the minimum and maximum factors for each CCS component system and for all systems combined.

[5] The length of the pipeline was assumed to be the distance to the closest potential geologic storage site, as identified by the University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, available at: http://www.beg.utexas.edu/gccc/graphics/Basemap_state_lands_fp_lg.jpg (last visited Aug. 11, 2011).

[6] "Cost estimates [for geologic storage of CO_2] are limited to capital and operational costs, and do not include potential costs associated with long-term liability." (from the *Report of the Interagency Task Force on Carbon Capture and Storage*, p. 44)

Table 5-2

GHG Emission Calculations - Calculation of Design Heat Rate Limit

Channel Energy Center, LLC

Base Net Heat Rate	**6,852**	**Btu/kWH (HHV) (Without Duct Firing)**
	3.3%	**Design Margin**
	6.0%	**Performance Margin**
	3.0%	**Degradation Margin**
Calculated Base Net Heat Rate with Compliance Margins	**7,727.9**	**Btu/kWH (HHV) (Without Duct Firing)**

Calculate of ton CO2e/MWhr Heat Rate Limit for CTG/HRSG3

EPN	Base Heat Rate (Btu/kWhr)	Heat Input Required to Produce 1 MW (MMBtu/hr)	Pollutant	Emission Factor (kg/MMBtu)[1]	ton GHG/MWhr[2]	Global Warming Potential[3]	ton CO_2e/MWhr
CTG/HRSG3	7727.9	7.73	CO_2		0.459	1	0.459
			CH_4	1.0E-03	8.52E-06	21	1.79E-04
			N_2O	1.0E-04	8.52E-07	310	2.64E-04
				Totals	**0.459**		**0.460**

Note

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} = (Fc x H x U_f X MW_{CO2})/2000

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

Fc = 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/lbmole

3. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

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.*[21]

An impacts analysis for non-GHG emissions is being submitted with the State/PSD/Non-attainment 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.*[22]

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, 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*

[21] EPA, *PSD and Title V Permitting Guidance For Greenhouse Gases* at 48-49.

[22] *Id.* at 49.

> *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.*[23]

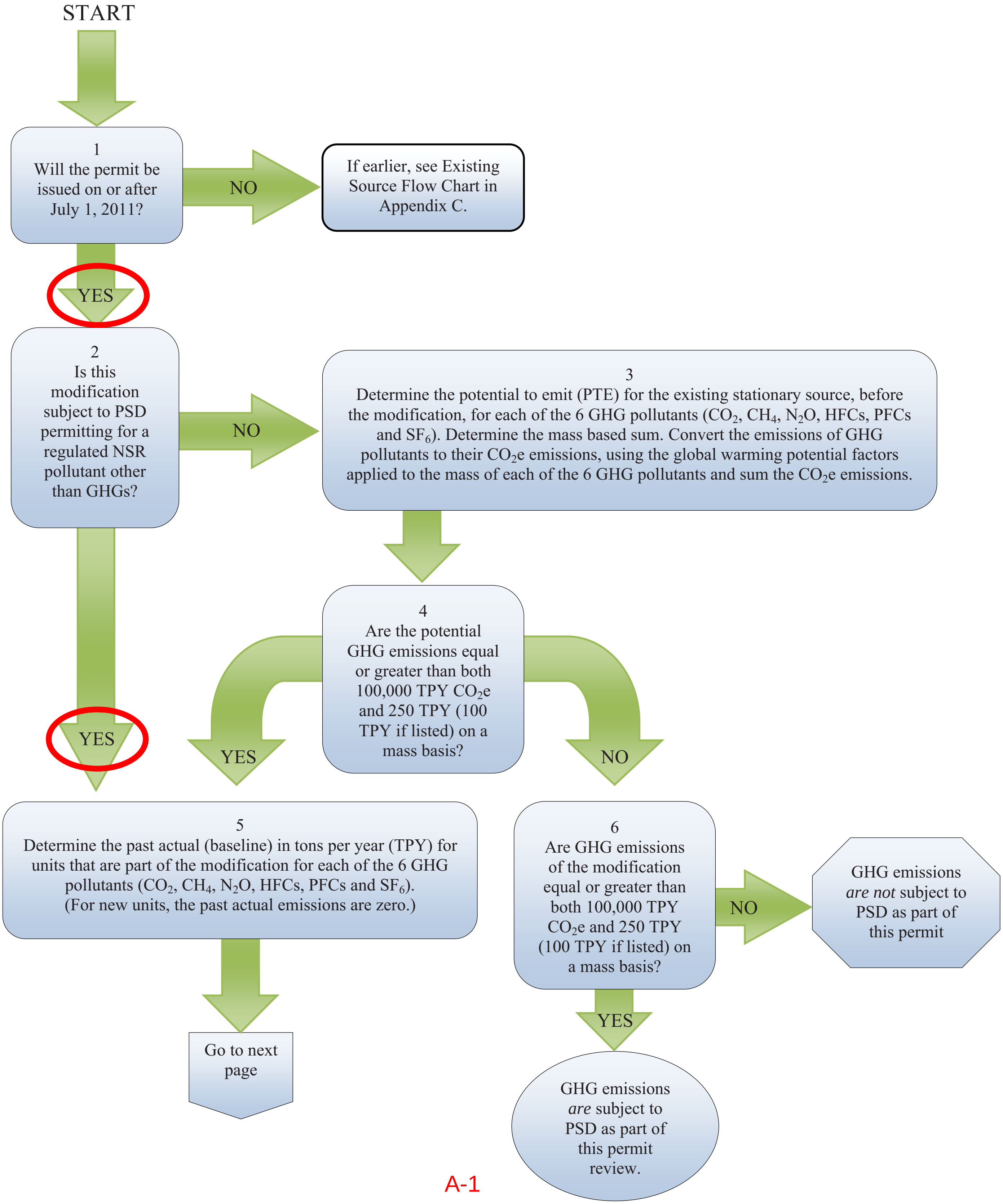
A PSD additional impacts analysis for non-GHG emissions is being submitted with the State/PSD/Nonattainment application submitted to the TCEQ.

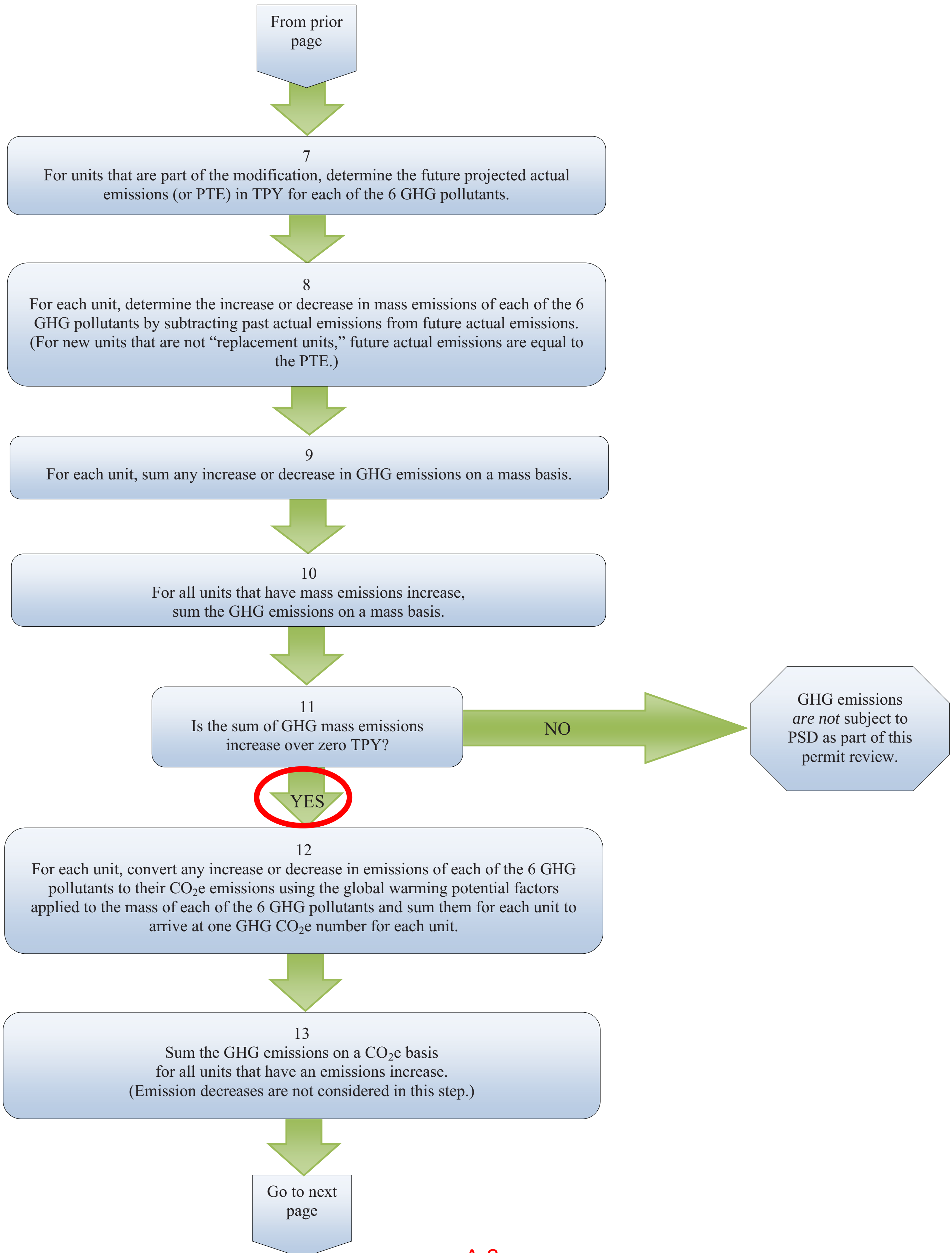
[23] *Id.*

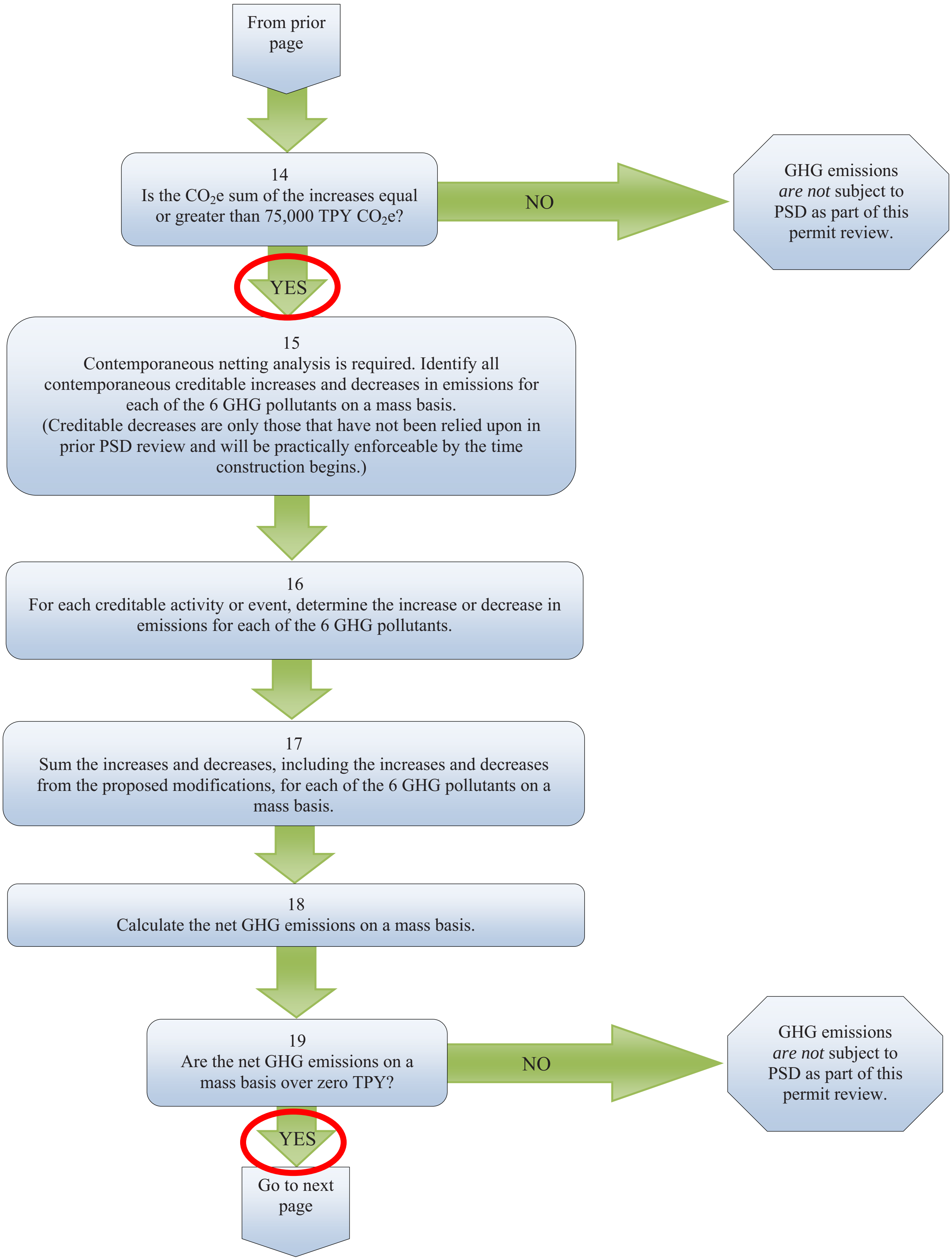
APPENDIX A

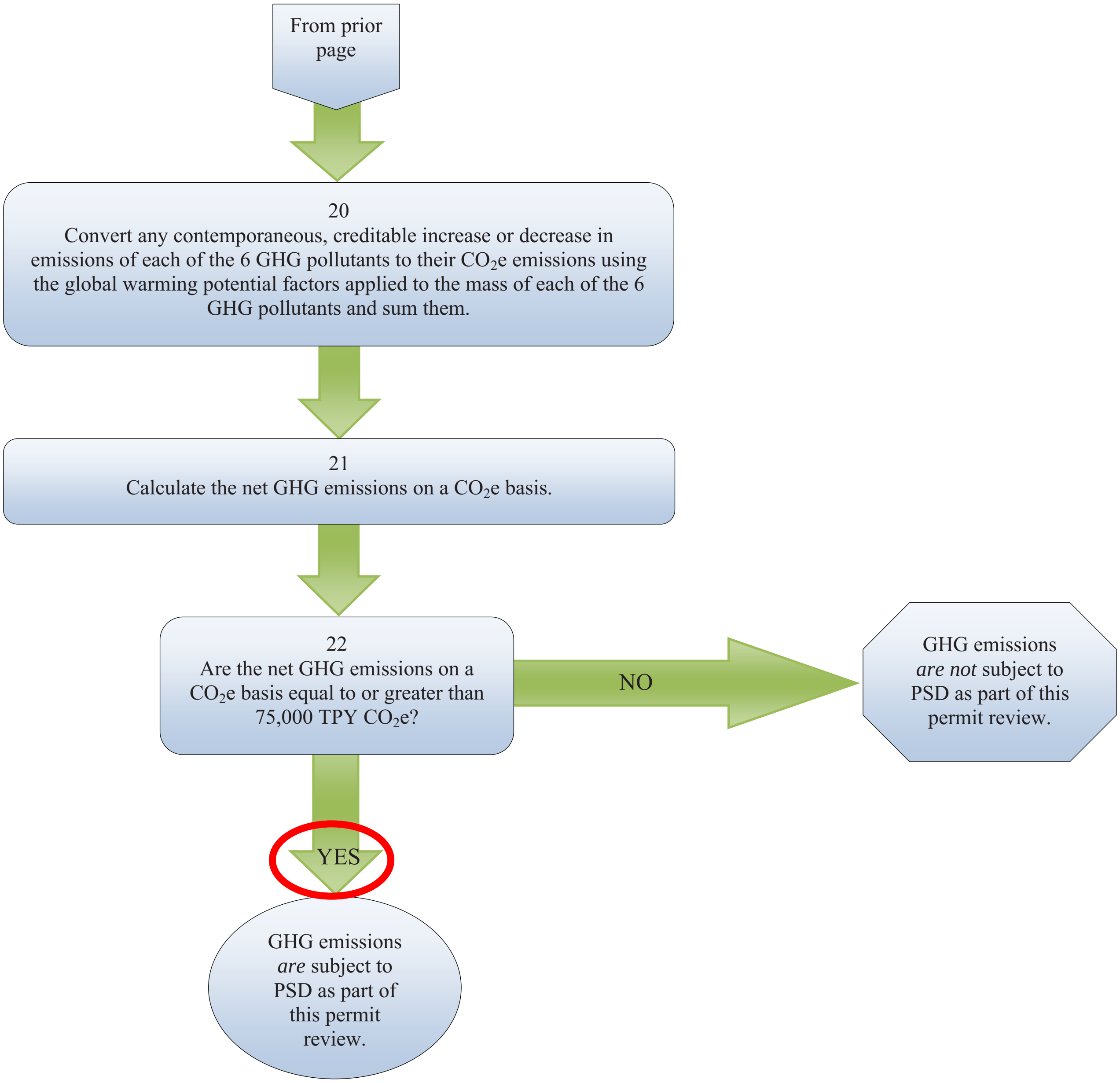
GHG PSD APPLICABILITY FLOWCHART – EXISTING SOURCES

GHG Applicability Flowchart – Modified Sources
(On or after July 1, 2011)




From prior page
7
For units that are part of the modification, determine the future projected actual emissions (or PTE) in TPY for each of the 6 GHG pollutants.
8
For each unit, determine the increase or decrease in mass emissions of each of the 6 GHG pollutants by subtracting past actual emissions from future actual emissions. (For new units that are not "replacement units," future actual emissions are equal to the PTE.)
9
For each unit, sum any increase or decrease in GHG emissions on a mass basis.
10
For all units that have mass emissions increase, sum the GHG emissions on a mass basis.
11
Is the sum of GHG mass emissions increase over zero TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
12
For each unit, convert any increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2e emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them for each unit to arrive at one GHG CO_2e number for each unit.
13
Sum the GHG emissions on a CO_2e basis for all units that have an emissions increase. (Emission decreases are not considered in this step.)
Go to next page


From prior page
14
Is the CO_2e sum of the increases equal or greater than 75,000 TPY CO_2e?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
15
Contemporaneous netting analysis is required. Identify all contemporaneous creditable increases and decreases in emissions for each of the 6 GHG pollutants on a mass basis.
(Creditable decreases are only those that have not been relied upon in prior PSD review and will be practically enforceable by the time construction begins.)
16
For each creditable activity or event, determine the increase or decrease in emissions for each of the 6 GHG pollutants.
17
Sum the increases and decreases, including the increases and decreases from the proposed modifications, for each of the 6 GHG pollutants on a mass basis.
18
Calculate the net GHG emissions on a mass basis.
19
Are the net GHG emissions on a mass basis over zero TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
Go to next page


From prior page
20
Convert any contemporaneous, creditable increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2e emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them.
21
Calculate the net GHG emissions on a CO_2e basis.
22
Are the net GHG emissions on a CO_2e basis equal to or greater than 75,000 TPY CO_2e?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.