El Paso Electric

P.O. Box 982
El Paso, Texas
79960-0982
(915) 543-5711

April 19, 2012

Mr. Jeff Robinson
Permit Section Chief
U.S. Environmental Protection Agency, (6PD-R)
1445 Ross Ave
Dallas, TX 75202-2733

RE: *Application for Prevention of Significant Deterioration for Greenhouse Gas Emissions*
El Paso Electric Company – Montana Power Station
El Paso County, Texas
Customer Number (CN): 600352819, Regulated Entity Number (RN): TBD

Dear Mr. Robinson:

El Paso Electric Company (EPEC) is proposing to construct an electric generating station and ancillary equipment at a facility (Montana Power Station Project) located on a 260-acre tract of land situated in East El Paso County, Texas, but not within the City of El Paso. The primary Standard Industrial Classification code of the proposed Montana Power Station is 4911 (Electric Services). EPEC has been assigned Texas Commission on Environmental Quality (TCEQ) Customer Reference Number (CN) 600352819. The Montana Power Station has not yet been assigned a TCEQ Regulated Entity Number (RN).

The proposed Montana Power Station will be a new major source with respect to greenhouse gas (GHG) emissions and subject to Prevention of Significant Deterioration (PSD) permitting requirements under the GHG Tailoring Rule. With a final action published in May 2011, EPA promulgated a Federal Implementation Plan (FIP) to implement the permitting requirements for GHGs in Texas, and EPA assumed the role of permitting authority for Texas GHG permit applications with that action. Therefore, GHG emissions from the proposed facility are subject to the jurisdiction of the EPA under authority EPA has asserted in Texas through its FIP for the regulation of GHGs. As shown in the enclosed permit application, the proposed Montana Power Station will be PSD major for nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), and particulate matter with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$). Therefore, a separate PSD application for all non-GHG pollutants is being submitted to the TCEQ under a separate cover.

This permit application is prepared in accordance with EPA guidance. This application includes a TCEQ Form PI-1, other applicable TCEQ forms, a Best Available Control Technology evaluation, emissions calculations, process description and flow diagrams, and supporting documentation.

If you have any questions or comments about the information presented in this letter, please do not hesitate to call Mr. Robert Daniels, EPEC's Project Manager, at (915) 543-4081 or myself at (915) 543-5827.

Sincerely,
EL PASO ELECTRIC COMPANY

Roger Chacon

Roger Chacon
Environmental Department Manager

Enclosure

cc: Air Permits Initial Review Team (APIRT), TCEQ Austin
Mr. Paul Greywall, Director, Trinity Consultants
Ms. Melissa Dakas, Managing Consultant, Trinity Consultants

El Paso Electric

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION FOR GREENHOUSE GASES

El Paso Electric Company > Montana Power Station

El Paso Electric Company
100 North Stanton Street
El Paso, TX 79901
(915) 543-4081
Fax: (915) 497-8372

Roger Chacon
Environmental Manager
Direct 915-543-543-5827
Cellular 915-539-0048

Robert Daniels PG, PE
Environmental Engineer-Air Program
Direct 915-543-4081
Cellular 915-497-8372

Prepared By:
TRINITY CONSULTANTS

Paul Greywall, P.E. – Director
Melissa Dakas – Managing Consultant

April 2012

Project 124401.0038

Trinity Consultants

Environmental solutions delivered uncommonly well

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El Paso Electric Company (EPEC) proposes to construct the Montana Power Station, a greenfield electric generating station and ancillary equipment located on a 260-acre tract of land situated in East El Paso County, Texas, outside of the City of El Paso. The primary Standard Industrial Classification code of the proposed Montana Power Station is 4911 (Electric Services). EPEC has been assigned Texas Commission on Environmental Quality (TCEQ) Customer Reference Number (CN) 600352819. The Montana Power Station has not yet been assigned a TCEQ Regulated Entity Number (RN). With this application, EPEC has included a Core Data Form for, and respectfully requests the assignment of, an RN for the proposed Montana Power Station.

The proposed Montana Power Station will be a new major source with respect to greenhouse gas (GHG) emissions and subject to Prevention of Significant Deterioration (PSD) permitting requirements administered by the U.S. Environmental Protection Agency (EPA) under a federal implementation plan imposed on sources within the State of Texas. 75 Fed. Reg. 77,698 (Dec. 13, 2010).

Accordingly, EPEC is submitting applications to both agencies (TCEQ and EPA) to obtain the requisite authorizations to construct. The TCEQ NSR PSD application submitted to TCEQ will also be submitted to EPA under a separate cover. This document constitutes EPEC's application for a GHG PSD Permit from the EPA to authorize the proposed Montana Power Station.

1.1 PROPOSED PROJECT

The Montana Power Station will be designed to have a total power generation output capacity of approximately 400 megawatts (MW) for peaking/intermediate load operation during all year demand periods. EPEC proposes to install four General Electric (GE) LMS100s combustion turbines to meet the 400 MW output demand. These are the highest-efficiency turbines for the intended service. The power generation configuration of the gas-fired turbines will be simple cycle with peaking capabilities. Selective catalytic reduction (SCR) will be employed as Best Available Control Technology (BACT) for emissions of NO_x. In addition, EPEC is proposing a GE supplied carbon monoxide reduction (COR) system to reduce emissions of CO and VOCs from the LMS100s.

Each simple cycle, gas-fired turbine-LMS100 Electric Generating Unit (EGU) will have a power generation output capacity of approximately 100 MW during the winter and 89.9 MW during extreme summer temperatures. The four EGUs will be constructed sequentially over a four year time period. In early 2013, EPEC will commence construction of one GE LMS100 EGU, which is proposed to be operational in 2014. The next stage of construction for the second LMS100 will begin in 2014 and the final stage of construction for the last two GE LMS100s is projected to be in 2015. The detailed analysis on selection of the simple cycle combustion technology and selection of the GE LM100s is provided in Appendix A.

The proposed Montana Power Station will include the following emissions sources:

- Four (4) Natural Gas-fired Combustion Turbines including planned maintenance, start-up, and shutdown (MSS) activities
- Two (2) Cooling Towers
- One (1) Diesel Firewater Pump Engine
- One (1) 300 gallon Diesel Storage Tank
- Fugitive emissions from piping components

A detailed process description is included in Section 6 of this permit application.

1.2. PERMITTING CONSIDERATIONS

PSD regulations define a stationary source as a major source if it emits or has the potential to emit (PTE) either of the following:

- 250 tons per year (tpy) or more of any PSD pollutant; or
- 100 tpy or more of any PSD pollutant and the facility belongs to one of the 28 listed PSD major facility categories.

The list of 28 does not specifically include combustion turbines; however, the nearest category is *Fossil Fuel-Fired Steam Electric Plants of more than 250 million Btu/hr heat input.*[1] The proposed Montana Power Station will consist of simple cycle combustion turbines with no steam involved in the electrical power produced by the proposed plant. Therefore, the project is not considered a PSD Listed source and the "major" source threshold is 250 tpy or more of any regulated pollutant. The potential emissions from criteria pollutants do not exceed 250 tpy; however, the Montana Power Station is a major source of Greenhouse Gas Emissions (GHGs) with respect to PSD permitting requirements (i.e., carbon dioxide equivalent [CO_2e] emissions greater than 100,000 tons per year [tpy]). According to EPA guidance, the "major for one, major for all" PSD policy applies to GHGs for any project occurring on or after July 1, 2011. Therefore, if a greenfield site is major for GHGs only, then the criteria pollutant emissions need to be compared to the Significant Emission Rates (SERs; i.e., 40 tpy for nitrogen oxides (NO_x), sulfur dioxide (SO_2), and volatile organic compounds (VOC), 100 tpy for carbon monoxide (CO), 25 tpy for particulate matter (PM), 15 tpy for particulate matter with an aerodynamic diameter of 10 microns or less [PM_{10}], and 10 tpy for particulate matter with an aerodynamic diameter of 2.5 microns or less [$PM_{2.5}$]) when determining PSD applicability for these pollutants. Based on emissions estimates for the Montana Power Station, will be PSD major for NO_X, CO, PM, PM_{10}, $PM_{2.5}$, and GHGs. Based on the specifications for pipeline quality natural gas, the proposed project is not subject to PSD review for VOC and SO_2.

GHG emissions for each applicable emission source were estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule (40 CFR 98, Subpart C, Tables C-1 and C-2 for natural gas and diesel). The potential to emit (PTE) of GHGs from the Montana Power Station will be greater than 100,000 tpy on a CO_2e basis. A summary of the GHG emissions from the proposed project, calculated on a CO_2e basis by use of the Global Warming Potentials set forth in Table A-1 to Subpart A of 40 CFR Part 98, is shown in Table 1-1 below.

Table 1-1. Montana Power Station- Proposed Project GHG Emissions

EPN	Emission Point Description	GHG Emission Rates (metric tons per year)				
		CO_2	CH_4	N_2O	SF_6	Total CO_2e
FWP-1	Fire Water Pump	7.85	0.00	0.00	-	7.88
GT-1	Combustion Turbine 1	227,601	5	0.43	-	227,840
GT-2	Combustion Turbine 2	227,601	5	0.43	-	227,840
GT-3	Combustion Turbine 3	227,601	5	0.43	-	227,840
GT-4	Combustion Turbine 4	227,601	5	0.43	-	227,840
CTBR-SF_6	Fugitive SF_6 Circuit Breaker Emissions	-	-	-	0.01	335
FUG-1	Components Fugitive Leak Emissions	-	0.13	-	-	2.81
	Total	**910,414**	**20.13**	**1.72**	**0.01**	**911,704**

[1] 40 CFR 52.21(b)(1)(i)(a)

1.3. PERMIT APPLICATION

All required supporting documentation for the permit application is provided in the following sections. The TCEQ Form PI-1 is included in Section 2 and a TCEQ Core Data form is found in Section 3 of this application. An area map indicating the site location and a plot plan identifying the location of various emission units at the site are included in Sections 4 and 5 of the report, respectively. A project description and process flow diagram are presented in Section 6. A summary of the emission calculations and the TCEQ Table 1(a) can be found in Sections 7 and 8 of this application.

Detailed federal regulatory requirements are provided in Section 9 and discussions of Best Available Control Technology (BACT) are provided in Section 10.

2. TCEQ FORM PI-1

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

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

I. Applicant Information		
A. Company or Other Legal Name: El Paso Electric Company		
Texas Secretary of State Charter/Registration Number (*if applicable*): 0001073400		
B. Company Official Contact Name: Andres R. Ramirez		
Title: VP-Power Generation		
Mailing Address: 100 N. Stanton		
City: El Paso	State: Texas	ZIP Code: 79901
Telephone No.: (915) 543-5887	Fax No.: (915) 543-5802	E-mail Address: andy.ramirez@epelectric.com
C. Technical Contact Name: Roger Chacon		
Title: MGR-Environmental		
Company Name: El Paso Electric		
Mailing Address: 100 N. Stanton		
City: El Paso	State: Texas	ZIP Code: 79901
Telephone No.: (915) 543-5887	Fax No.: (915) 543-5802	E-mail Address: roger.chacon@epelectric.com
D. Site Name: Montana Power Station		
E. Area Name/Type of Facility: Montana Power Station		☒ Permanent ☐ Portable
F. Principal Company Product or Business:		
Principal Standard Industrial Classification Code (SIC): 4911		
Principal North American Industry Classification System (NAICS): 221112 (Fossil Fuel Electric Power Generation)		
G. Projected Start of Construction Date: January 2013		
Projected Start of Operation Date: January 2014		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: A Portion of Section 25, block 79, Township 2, Texas and Pacific Railway Surveys		
City/Town: El Paso	County: El Paso	ZIP Code: 79938
Latitude (nearest second): 31°49'26" N	Longitude (nearest second): 106°12'43" W	

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I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility):	
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): 600352819	
L. Regulated Entity Number (RN):	
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: 18	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: José Rodríguez	District No.: 29
Representative: Chente Quintanilla	District No.: 75
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested. Initial ☒ Amendment ☐ Revision (30 TAC 116.116(e)) ☐ Change of Location ☐ Relocation ☐	
B. Permit Number (if existing):	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* Construction ☒ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ 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.): **To Be Determined**			
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 ☐			

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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). New Mexico		
E.	Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3. **NO**	
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*): **Please see Permit Application Report**	
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: Roger Chacon		
Title: MGR-Environmental		
Mailing Address: 100 N. Stanton		
City: El Paso	State: Texas	ZIP Code: 79901
B. Name of the Public Place: Esperanza Acosta Moreno Library		
Physical Address (No P.O. Boxes): 12480 Pebble Hills		
City: El Paso	County: El Paso	ZIP Code: 79938
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: Veronica Escobar		
Mailing Address: 500 E. San Antonio		
City: El Paso	State: Texas	ZIP Code: 79901
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: Veronica Escobar		
Mailing Address: 500 E. San Antonio		
City: El Paso	State: Texas	ZIP Code: 79901
Name of the Federal Land Manager:		
Title:		
Mailing Address:		
City:	State:	ZIP Code:

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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 ☐ **N/A**
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 hours/day	Day(s): 7 days/week	Week(s):52 weeks/year	Year(s): See Application
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

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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: 1137562		Fee Amount: $ 75,000
Company name on check: El Paso Electric Company		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: Andres R. Ramirez
Signature: ______ *Original Signature Required*
Date: 4/19/12

3. TCEQ CORE DATA FORM

TCEQ Use Only

TCEQ Core Data Form

For detailed instructions regarding completion of this form, please read the Core Data Form Instructions or call 512-239-5175.

SECTION I: General Information

1. Reason for Submission *(If other is checked please describe in space provided)*

☒ New Permit, Registration or Authorization *(Core Data Form should be submitted with the program application)*

☐ Renewal *(Core Data Form should be submitted with the renewal form)* ☐ Other

2. Attachments ☒Yes ☐No

Describe Any Attachments: *(ex. Title V Application, Waste Transporter Application, etc.)* NSR Initial Permit Application

3. Customer Reference Number ***(if issued)*** CN 600352819

Follow this link to search for CN or RN numbers in Central Registry**

4. Regulated Entity Reference Number ***(if issued)*** RN

SECTION II: Customer Information

5. Effective Date for Customer Information Updates (mm/dd/yyyy)

6. Customer Role (Proposed or Actual) – *as it relates to the Regulated Entity listed on this form. Please check only one of the following:*

☐ Owner ☐ Operator ☒ Owner & Operator

☐ Occupational Licensee ☐ Responsible Party ☐ Voluntary Cleanup Applicant ☐ Other:

7. General Customer Information

☐ New Customer ☐ Update to Customer Information ☐ Change in Regulated Entity Ownership

☐ Change in Legal Name (Verifiable with the Texas Secretary of State) ☒ No Change**

*****If "No Change" and Section I is complete, skip to Section III – Regulated Entity Information.***

8. Type of Customer:	☒ Corporation	☐ Individual	☐ Sole Proprietorship- D.B.A
☐ City Government	☐ County Government	☐ Federal Government	☐ State Government
☐ Other Government	☐ General Partnership	☐ Limited Partnership	☐ Other:

9. Customer Legal Name *(If an individual, print last name first: ex: Doe, John)* El Paso Electric Corporation

If new Customer, enter previous Customer below — *End Date:*

10. Mailing Address: 100 N. Stanton

City	El Paso	**State**	TX	**ZIP**	79901	**ZIP + 4**	

11. Country Mailing Information *(if outside USA)*

12. E-Mail Address *(if applicable)* andy.ramirez@epelectric.com

13. Telephone Number (915) 543-5887

14. Extension or Code

15. Fax Number *(if applicable)* (915) 542-5802

16. Federal Tax ID *(9 digits)*

17. TX State Franchise Tax ID *(11 digits)*

18. DUNS Number *(if applicable)*

19. TX SOS Filing Number *(if applicable)* 0001073400

20. Number of Employees

☐ 0-20 ☐ 21-100 ☐ 101-250 ☐ 251-500 ☒ 501 and higher

21. Independently Owned and Operated? ☒ Yes ☐ No

SECTION III: Regulated Entity Information

22. General Regulated Entity Information *(If 'New Regulated Entity" is selected below this form should be accompanied by a permit application)*

☒ New Regulated Entity ☐ Update to Regulated Entity Name ☐ Update to Regulated Entity Information ☐ No Change** *(See below)*

****If "NO CHANGE" is checked and Section I is complete, skip to Section IV, Preparer Information.**

23. Regulated Entity Name *(name of the site where the regulated action is taking place)*

Montana Power Station

24. Street Address of the Regulated Entity: ***(No P.O. Boxes)***								
	City	El Paso	State	TX	ZIP	79938	ZIP + 4	
25. Mailing Address:	Roger Chacon							
	100 N. Stanton							
	City	El Paso	State	TX	ZIP	79901	ZIP + 4	
26. E-Mail Address:	roger.chacon@epelectric.com							

27. Telephone Number	28. Extension or Code	29. Fax Number *(if applicable)*
(915) 543-5887		(915) 543-5802

30. Primary SIC Code (4 digits)	31. Secondary SIC Code (4 digits)	32. Primary NAICS Code (5 or 6 digits)	33. Secondary NAICS Code (5 or 6 digits)
4911		221112	

34. What is the Primary Business of this entity? *(Please do not repeat the SIC or NAICS description.)*

Power Generation

Questions 34 – 37 address geographic location. Please refer to the instructions for applicability.

35. Description to Physical Location:	A Portion of Section 25, block 79, Township 2, Texas and Pacific Railway Surveys

36. Nearest City	County	State	Nearest ZIP Code
El Paso	El Paso	TX	79938

37. Latitude (N) In Decimal:			38. Longitude (W) In Decimal:		
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
31	49	26	106	12	43

39. TCEQ Programs and ID Numbers Check all Programs and write in the permits/registration numbers that will be affected by the updates submitted on this form or the updates may not be made. If your Program is not listed, check other and write it in. See the Core Data Form instructions for additional guidance.

☐ Dam Safety	☐ Districts	☐ Edwards Aquifer	☐ Industrial Hazardous Waste	☐ Municipal Solid Waste
☒ New Source Review – Air	☐ OSSF	☐ Petroleum Storage Tank	☐ PWS	☐ Sludge
☐ Stormwater	☐ Title V – Air	☐ Tires	☐ Used Oil	☐ Utilities
☐ Voluntary Cleanup	☐ Waste Water	☐ Wastewater Agriculture	☐ Water Rights	☐ Other:

SECTION IV: Preparer Information

40. Name:	Robert Daniels	**41. Title:**	Project Manager

42. Telephone Number	43. Ext./Code	44. Fax Number	45. E-Mail Address
(915) 543-4081		(915) 543-5802	Robert.Daniels@epelectric.com

SECTION V: Authorized Signature

46. By my signature below, I certify, to the best of my knowledge, that the information provided in this form is true and complete, and that I have signature authority to submit this form on behalf of the entity specified in Section II, Field 9 and/or as required for the updates to the ID numbers identified in field 39.

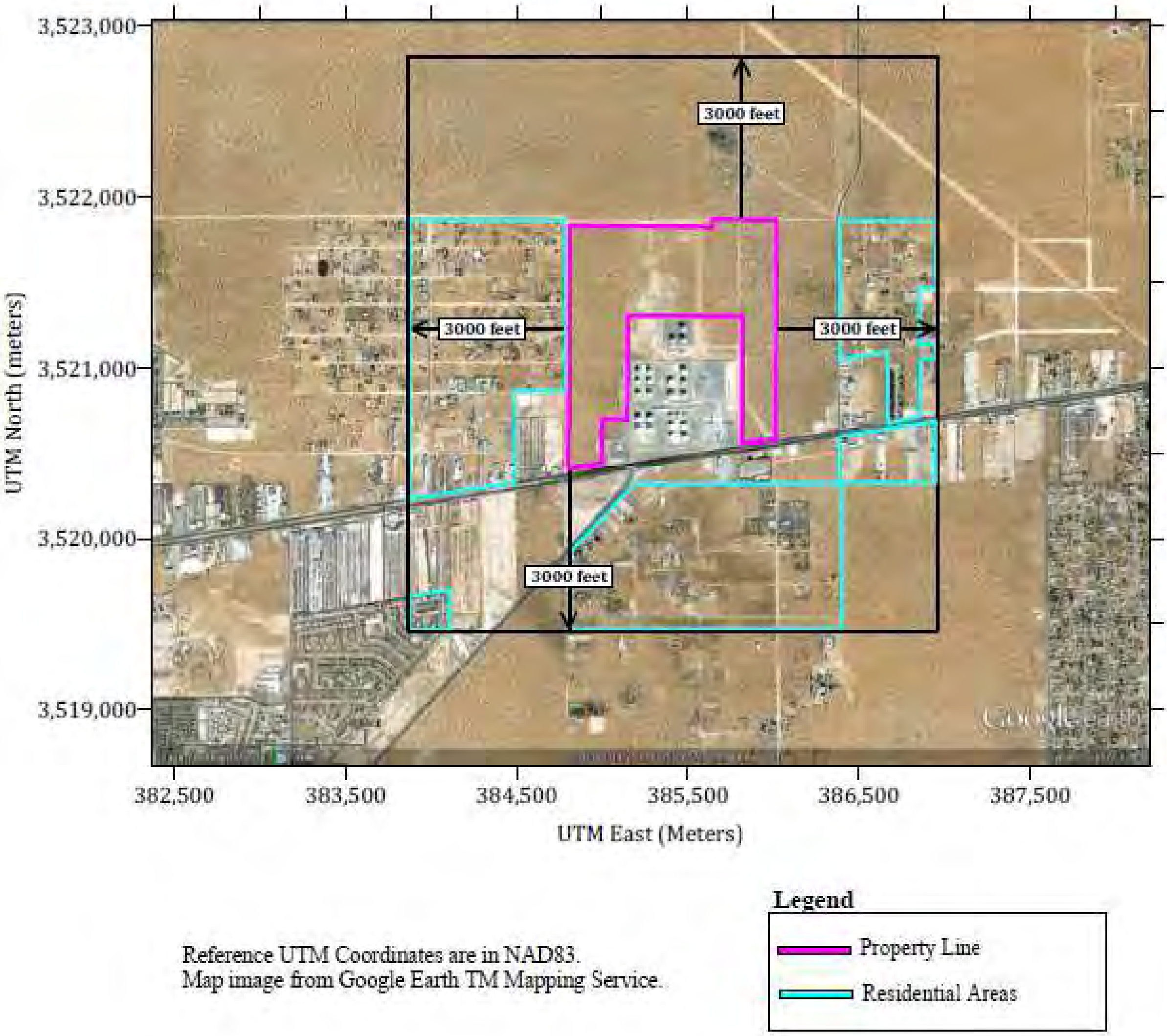
(See the Core Data Form instructions for more information on who should sign this form.)

Company:	El Paso Electric Company	**Job Title:**	VP-Power Generation
Name *(In Print)*:	Andres R. Ramirez	**Phone:**	(915) 543-5887
Signature:	[signature]	**Date:**	4/19/12

4. AREA MAP

The Montana Power Station is to be located in El Paso County, Texas. An area map is included in this section to graphically depict the location of the facility with respect to the surrounding topography. Figure 4-1 is an area map centered on the Montana Power Station site that extends out at least 3,000 feet from the property line in all directions. The map depicts the fenceline/property line with respect to predominant geographic features (such as highways, roads, streams, and railroads). The image shows there are no schools within 3,000 feet of the facility boundary.

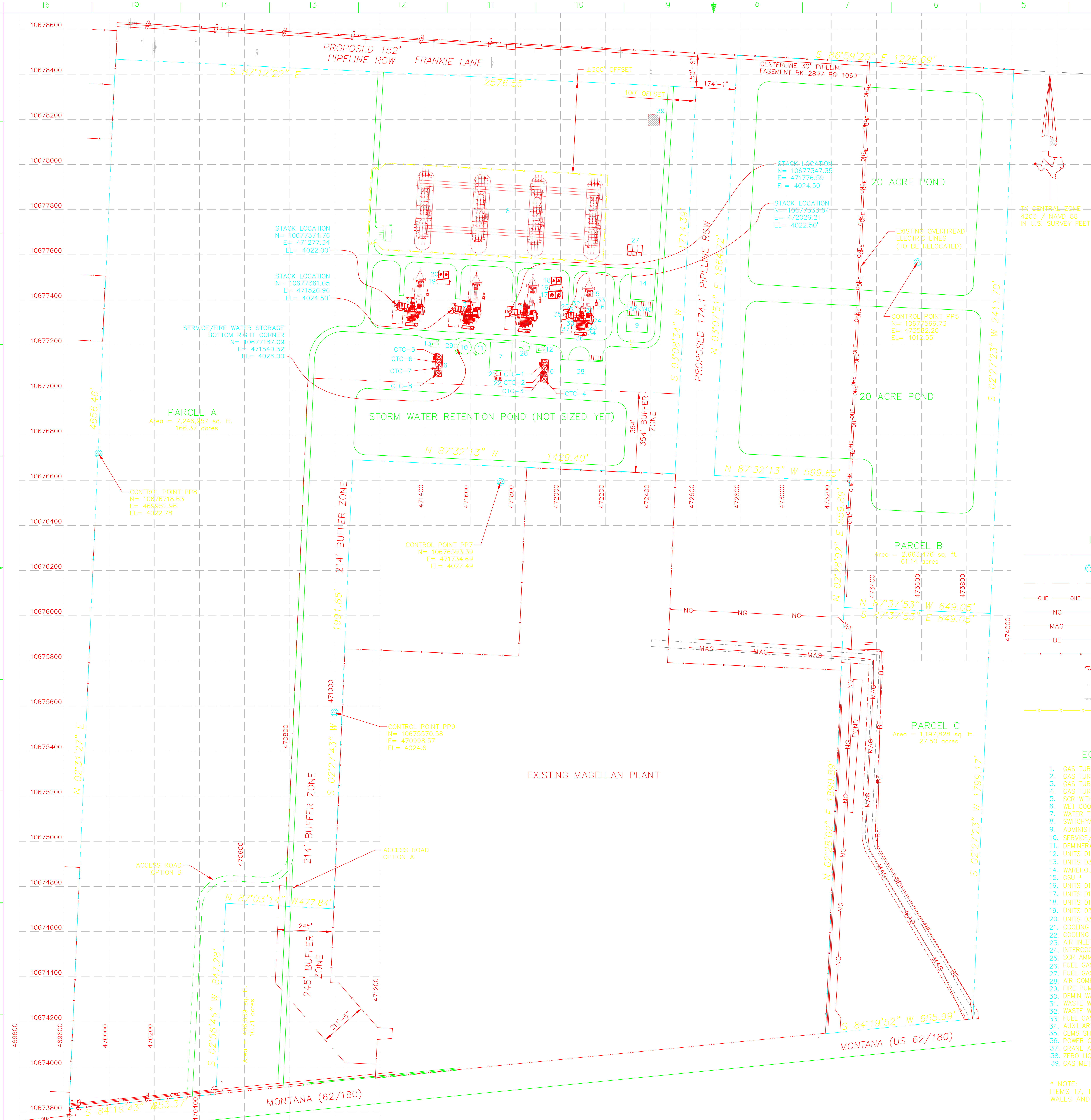
Figure 4-1
El Paso Electric Company
Montana Power Station Area Map



Reference UTM Coordinates are in NAD83.
Map image from Google Earth TM Mapping Service.

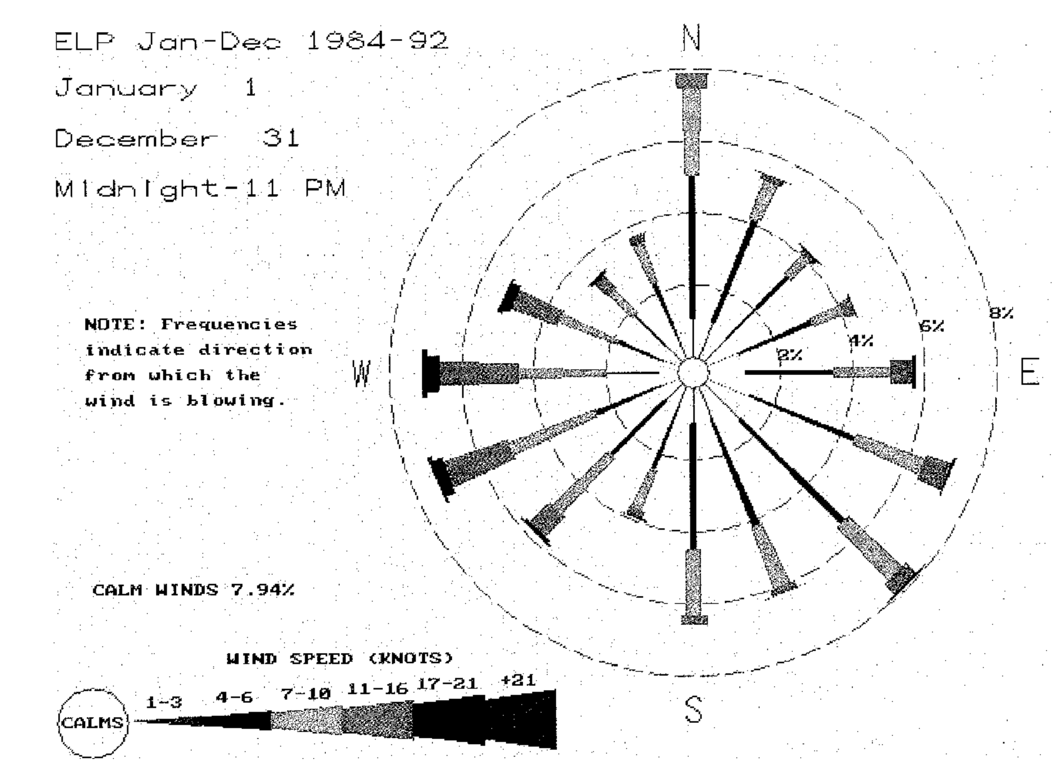
5. PLOT PLAN

The following figure depicts the site plans for the proposed Montana Power Station.



GENERAL NOTES:

1. PROPERTY BOUNDARY SURVEY SHOWN IS PROVIDED BY ZWA PROFESSIONAL LAND SURVEYORS OF EL PASO TEXAS. THE BOUNDARY INFORMATION ON THE DRAWING IS PRELIMINARY.
2. TOPOGRAPHICAL AERIAL SURVEY DATA (GROUND) ELEVATIONS SHOWN ARE BASED ON (NSSDA) FOR A CONTOUR INTERVAL OF 1 FOOT AND A MAP SCALE OF 1"=40'. SURVEY PERFORMED BY COOPER AERIAL SURVEYS COMPANY OF TUCSON ARIZONA, DATED DECEMBER 22, 2011.



WIND ROSE DATA

COOLING TOWER CELL LOCATIONS

NUMBER	NORTHING	EASTING	ELEVATION
CTC-1	10677121.71	471931.38	4024.50
CTC-2	10677097.41	471930.04	4025.50
CTC-3	10677073.16	471928.69	4026.00
CTC-4	10677048.87	471927.36	4026.00
CTC-5	10677147.52	471462.09	4026.00
CTC-6	10677123.22	471460.75	4026.50
CTC-7	10677098.93	471459.35	4027.00
CTC-8	10677074.63	471458.02	4027.00

CONCEPTUAL
ISSUED FOR REVIEW

150' 0 150' 300' 450'
Scale 1" = 150'

LEGEND

- PROPERTY LINE
- CONTROL POINT
- BUFFER LINE
- OHE — EXISTING OVERHEAD ELECTRIC LINE
- NG — EXISTING NG PIPELINE
- MAG — EXISTING MAG PIPELINE
- BE — EXISTING BE PIPELINE
- EXISTING BARBED WIRE FENCE LINE
- EXISTING ELECTRIC POLE
- EXISTING SIGN
- EXISTING PIPELINE MARKER SIGNS
- X — NEW FENCE LINE

EQUIPMENT

1. GAS TURBINE GENERATOR UNIT 01
2. GAS TURBINE GENERATOR UNIT 02
3. GAS TURBINE GENERATOR UNIT 03
4. GAS TURBINE GENERATOR UNIT 04
5. SCR WITH STACK
6. WET COOLING TOWER
7. WATER TREATMENT BUILDING
8. SWITCHYARD
9. ADMINISTRATION/CONTROL BUILDING
10. SERVICE/FIRE WATER STORAGE TANK
11. DEMINERALIZED WATER STORAGE TANK
12. UNITS 01/02 AQUEOUS AMMONIA STOR TKS
13. UNITS 03/04 AQUEOUS AMMONIA STOR TKS
14. WAREHOUSE
15. GSU *
16. UNITS 01/02 SWITCHGEAR BUILDING
17. UNITS 01/02 AUXILIARY TRANSFORMERS *
18. UNITS 01/02 STA. SERVICE TRANSFORMERS *
19. UNITS 03/04 SWITCHGEAR BUILDING
20. UNITS 03/04 STA. SERVICE TRANSFORMERS *
21. COOLING TOWER SWITCHGEAR BUILDING
22. COOLING TOWER TRANSFORMERS *
23. AIR INLET FILTER
24. INTERCOOLER
25. SCR AMMONIA INJECTION GRID
26. FUEL GAS FILTER/COALESCER SKID
27. FUEL GAS COMPRESSORS
28. AIR COMPRESSORS AND CONDITIONING
29. FIRE PUMP HOUSE
30. DEMIN WATER SKID
31. WASTE WATER WASH TANK
32. WASTE WATER PLANT TANK
33. FUEL GAS WASTE TANK
34. AUXILIARY SKID
35. CEMS SHELTER
36. POWER CONTROL MODULE
37. CRANE ACCESS AREA
38. ZERO LIQUID DISCHARGE BUILDING
39. GAS METERING STATION

* NOTE:
ITEMS 17, 18, 20 & 22 TO HAVE BLAST WALLS AND FIRE DELUGE SYSTEM

REV	DATE	DESCRIPTION	DRAWN	CHECKED	LEAD DESIGNER	ENGINEER/ TECH SPEC	LEAD DISC ENGINEER	PROJ ENGR MANAGER	PROJECT MANAGER
A	03 15 12	ISSUED FOR REVIEW	GLG	DAW	BDC	JHP	JHP	CWD	JHD

PRELIMINARY STATUS — DATE
LDE JH PARRIS 03/15/2012
INFORMATION ONLY - NOT TO BE USED FOR CONSTRUCTION.

APPROVED STATUS — DATE
LDE
REPRESENTS REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.

ORIGINATING PERSONNEL
DRAWN BY: GL GRANT
CHECKED BY: DA WILSON
LEAD DESIGNER: BD CARVER
ENGINEER/TECH SPECIALIST: JH PARRIS
PROJECT ENGINEERING MANAGER: CW DUEKER
PROJECT MANAGER: JH DYER

PROFESSIONAL ENGINEER'S SEAL
ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF
PE: STATE:
LIC. NO.: DATE:

OneWay to zero harm

WorleyParsons
resources & energy

The Electric Company
El Paso Electric

CLIENT/PROJECT TITLE
EL PASO ELECTRIC
EL PASO, TEXAS
LMS-100 SIMPLE CYCLE

CONCEPTUAL
GENERAL ARRANGEMENT
OVERALL SITE PLAN

SCALE: 1" = 150'
DRAWING SIZE: ANSI E (44" x 34")
WORLEYPARSONS DWG. NO.: EPEM-00-DW-012-735-001
REV: A

6. PROCESS DESCRIPTION

The Montana Power Station will consist of four GE Gas-Fired Turbines (Model LMS100) and associated equipment including cooling towers, a firewater pump engine, ammonia storage tanks, circuit breakers, and unloading system, and a diesel storage tank. A process flow diagram is included at the end of this section. In addition, maintenance, start-up, and shutdown emissions are detailed below.

6.1. COMBUSTION TURBINES

The GE LMS100 combustion turbines at the proposed Montana Power Station will be natural gas –fired and operated in simple cycle configuration, with a power generation capacity of 100 MW per combustion turbine (FIN/EPNs: GT-1, GT-2, GT-3, and GT-4). The GE LMS100 systems provide the highest simple cycle efficiency in the power generation industry. These systems combine the frame and aeroderivative gas turbine technologies, which provide high simple cycle efficiency (44% base load efficiency), fast starts (capability to deliver 100 MW in 10 minutes), high availability and reliability and cyclic capability without maintenance impact. [2] The detailed design features, configuration, and performance specification of the GE LMS100 combustion turbines are provided in Appendix C.

Each LMS100 combustion turbine will be equipped with a water-injection system (to control NO_X emissions), SCR system (to control post-combustion NO_X emissions), and a COR system (to control CO and VOC emissions). The SCR system will use 19% aqueous ammonia.

In order to meet the peak demands in power all year long, the combustion turbines will require more frequent startup and shutdowns (SUSD). The details of the SUSD events and the duration are provided in Section 7 of this application and in emission calculations.

6.2. COOLING TOWERS

The Montana Power Station will install two cooling towers (FIN/EPNs: CT-1 and CT-2). Each cooling tower will support two combustion turbines and will be equipped with four cells, with two cells serving each LMS100 combustion turbine. The cooling towers will be equipped with high efficiency drift eliminators to control particulate matter generated from the drift droplets. The cooling towers are not a source of GHG emissions.

6.3. FIREWATER PUMP ENGINE

A 327-hp diesel-fired firewater pump engine will be used for emergency purposes (FIN/EPN: FWP-1). Other than during plant emergency situations, the firewater pump engine will be operated for less than one hour per week for routine testing, maintenance, and inspection purposes only.

6.4. AMMONIA STORAGE AND UNLOADING SYSTEM

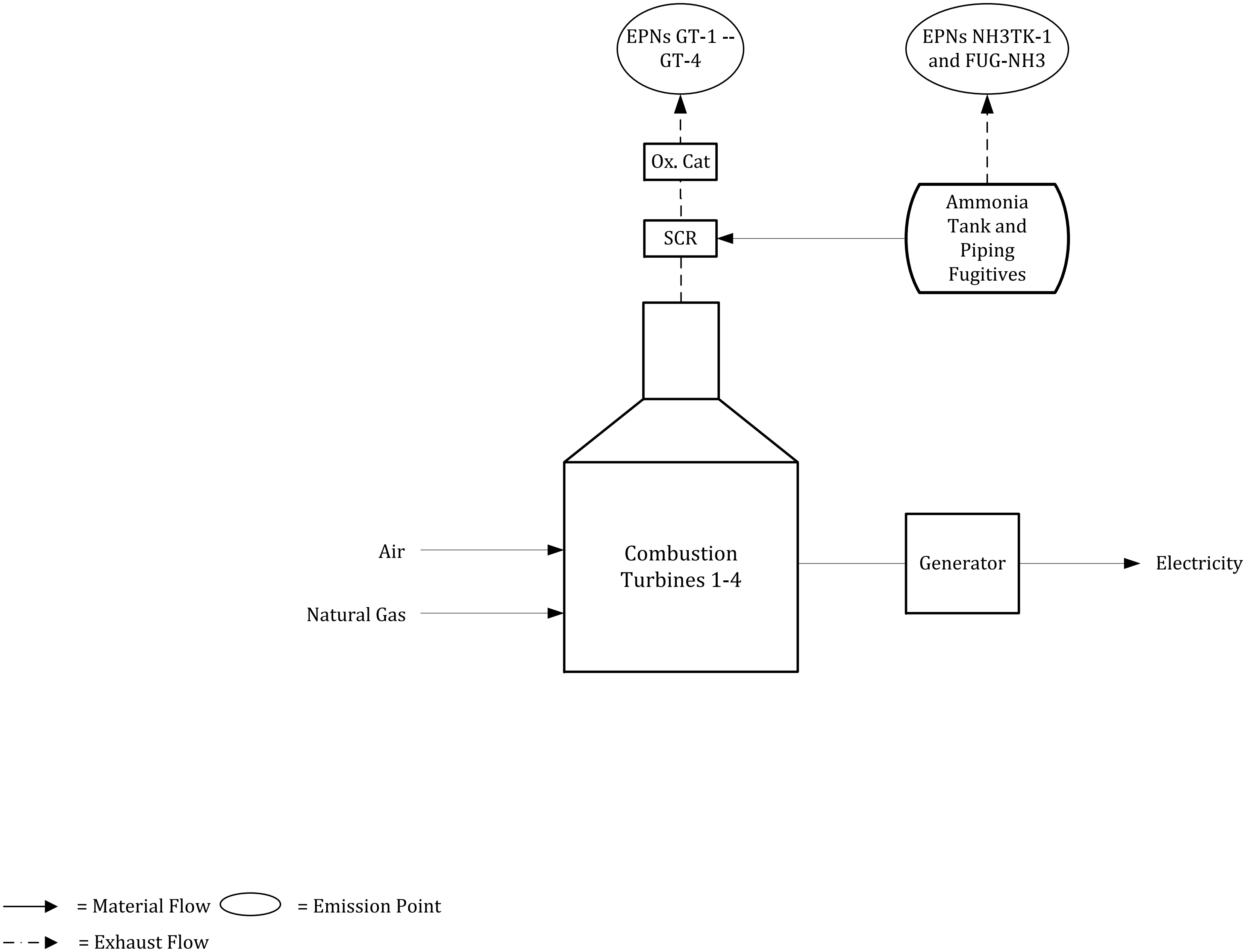
Aqueous ammonia (19%) used in the SCR system will be brought on-site via tank trucks and unloaded into two horizontal storage tanks (approximately 20,000 gallon capacity, each). The NH_3 unloading system will be equipped with a vapor return line to collect NH_3 vapors generated during unloading and will be routed back to the tank truck using a vacuum system. Aqueous ammonia will be transferred to the SCR system using transfer pumps and pipelines. Therefore, the ammonia storage tanks and unloading operations are not considered as potential emission sources;

[2] Obtained from GE's "New High Efficiency Simple Cycle Gas Turbine – GE's LMS100", available at: http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf (accessed February, 2012).

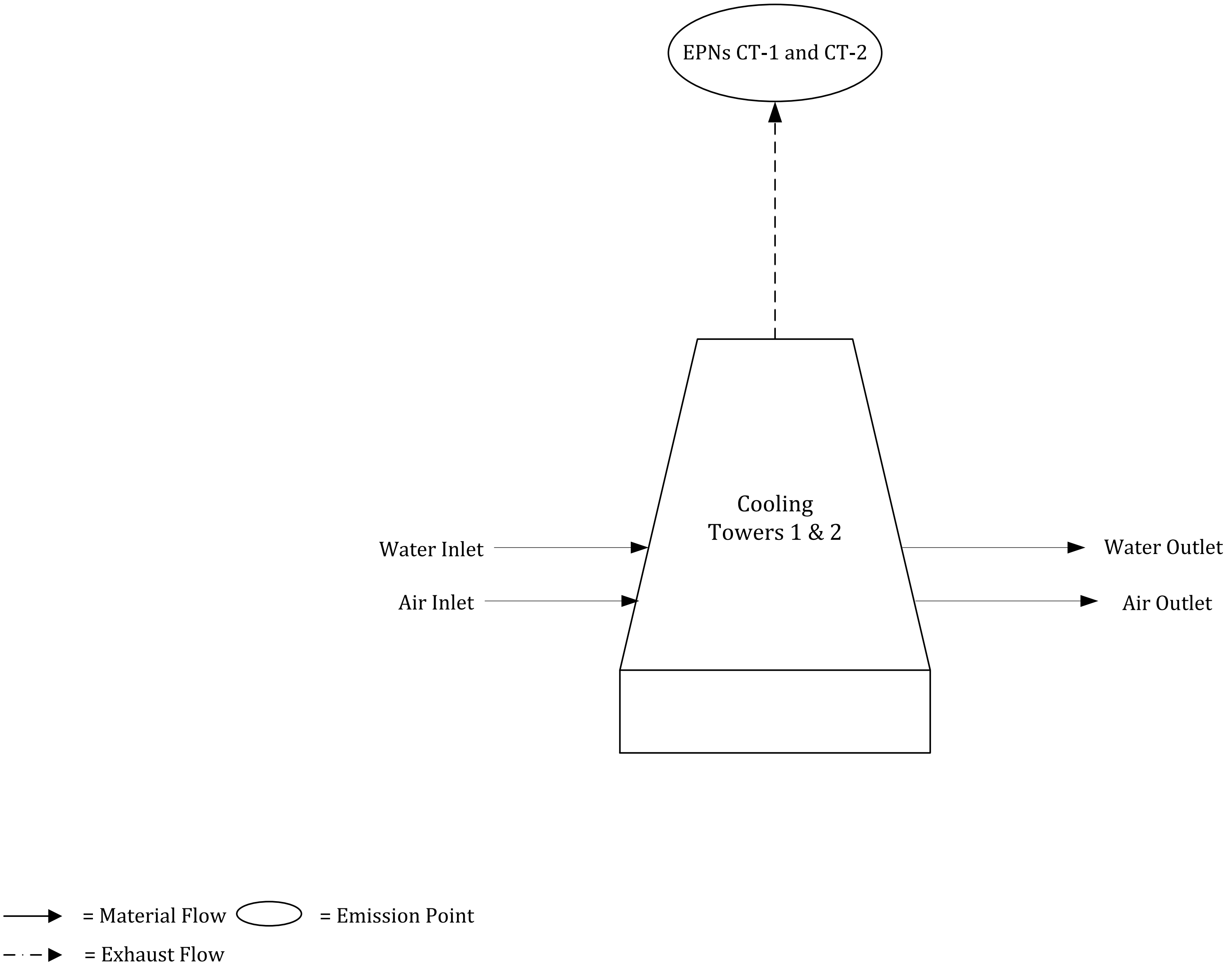
however, fugitive emissions of NH_3 will be produced from equipment leaks from components in ammonia service. The ammonia storage and unloading system are not a source of GHG emissions.

6.5. DIESEL STORAGE TANK

Diesel used the firewater pump engine will be stored in a 300-gallon (approximate capacity) horizontal storage tank (FIN/EPN: DIESEL). The tank will be located inside the firewater pump engine building. The diesel storage tank is not a source of GHG emissions.



	TITLE	DATE	DRAWN BY
El Paso Electric; El Paso County	**El Paso Electric Company - Montana Power Station** **Process Flow Diagram** **Figure 1. Simple Cycle Combustion Turbines**	April 2012	Trinity Consultants



	TITLE	DATE	DRAWN BY
El Paso County	**El Paso Electric Company - Montana Power Station** **Process Flow Diagram** **Figure 2. Cooling Towers**	April 2012	Trinity Consultants

7. EMISSIONS DATA

This section summarizes the GHG emission calculation methodologies and provides emission calculations for the emission sources of GHGs at the proposed Montana Power Station. Detailed emission calculation spreadsheets, including example calculations, are included in Appendix B. These emission estimates reflect the emission limits chosen as BACT in Section 10.

Potential GHG emissions from the proposed project will result from the following emission units:

- Four Simple Cycle Combustion Turbines (EPNs: GT-1, GT-2, GT-3, GT-4)
- One Fire Water Pump (EPN: FWP-1)
- Fugitive Emissions from SF_6 Circuit Breakers (EPNs: CTBR-SF_6)
- Fugitive Emissions from Piping Components (EPN: FUG-1)

Table 7-1 provides a summary of the annual potential to emit emissions of GHGs for the proposed project

Table 7-1. Proposed Project Potential GHG Emissions

Source	Annual Potential GHG Emissions (tpy – metric tons)				
	CO_2	CH_4	N_2O	SF_6	CO_2e
Combustion Turbines	910,406	20.0	1.72	--	911,359
Fire Water Pump	7.85	<0.01	<0.01	--	7.88
SF_6 Circuit Breakers	--	--	--	0.01	335
Components Fugitive Leak Emissions	--	0.13	--	--	2.81
Total Project Emissions	**910,414**	**20.13**	**1.72**	**0.01**	**911,704**

GHG emissions for each emission unit were estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule (40 CFR 98, Subpart C, Tables C-1 and C-2 for natural gas and diesel).

According to 40 CFR §52.21(b)(49)(ii), GHG emissions for PSD applicability must show CO_2e emissions calculated by multiplying the mass of each of the six GHGs by the gas's associated global warming potential (GWP), which is established in Table A-1 to Subpart A of 40 CFR Part 98. Table 7-2. Global Warming Potentials provides the GWP for each GHG emitted from this proposed project.

Table 7-2. Global Warming Potentials

Pollutant	GWP[1]
CO_2	1
CH_4	21
N_2O	310
SF_6	23,900

1. GWPs are based on a 100-year time horizon, as identified in Table A-1 to 40 CFR Part 98, Subpart A.

The following is an example calculation for annual CO_2e emissions:

$$CO_2e \text{ Annual Emission Rate (tpy)}$$
$$= CO_2 \text{ Annual Emission Rate (tpy)} \times CO_2 \text{ GWP } + CH_4 \text{ Annual Emission Rate (tpy)} \times CH_4 \text{ GWP}$$
$$+ N_2O \text{ Annual Emission Rate (tpy)} \times N_2O \text{ GWP}$$
$$+ SF_6 \text{ Annual Emission Rate (tpy)} \times SF_6 \text{ GWP}$$

7.1. COMBUSTION TURBINES

The proposed project will include four simple cycle natural gas fired combustion turbines (EPNs: GT-1, GT-2, GT-3, GT-4). Combustion of natural gas will result in GHG emissions of CO_2, CH_4, and N_2O. Each turbine is rated at a maximum heat input capacity of 806 MMBtu/hr (HHV). The annual hours of operation for each combustion turbine will be limited to 5,000 hours per year (hr/yr), including startup and shutdown events.

GHG emissions are estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule (MRR). See Appendix B for detailed emission calculations.

$$\mathbf{CO_2, CH_4 \text{ or } N_2O = 1 \times 10^{-3} * Fuel * HHV * EF \qquad \ldots \text{ Eq. C-1 \& C-8}}$$

Where each parameter is defined and further discussed below.

Parameter	Description	Remarks
CO_2 , CH_4, or N_2O	Annual CO_2, CH_4, or N_2O mass emissions (metric tons/year)	
Fuel	Maximum Potential Natural Gas Usage per year (scf/yr)	[Rated Capacity (MMBtu/hr) * 5000 hours/yr Potential Operation] / (Natural Gas HHV)
HHV	Site specific natural gas heating value obtained from the natural gas analysis	0.001014 MMBtu/scf
EF	Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/MMBtu) OR Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 of this subpart (kg CH_4 or N_2O per MMBtu).	53.02 kg CO_2/MMBtu 0.001 kg CH_4/MMBtu 0.0001 kg N_2O/MMBtu

GHG emissions from maintenance, startup, and shutdown activities are caused from the combustion of natural gas and the release of unburned methane. The proposed annual hours of operating limit of 5000 hours for each turbine includes all hours of startup and shutdown activities. Therefore the startup and shutdown emissions from the combustion of natural gas are already included in the calculations above. In addition to the combustion emissions, each turbine will release a small amount of unburned methane during a startup or shutdown event:

Start-up Emissions = 0.8 lbs/event

Shutdown Emissions = 1.07 lbs/event

Each turbine will have up to 832 startup and 832 shutdown events each year.

Annual Startup emissions (metric tpy) = Maximum Turbine Starts (events/yr) x Emissions per Event (lbs/ event) / (2204.623 lbs/metric ton)

Annual Shutdown emissions (metric tpy) = Maximum Turbine Shutdowns (events/yr) x Emissions per Event (lbs/ event) / (2204.623 lbs/metric ton)

7.2. FIRE WATER PUMP

One 327-hp diesel fire pump (EPN: FWP-1) will be installed at the facility for the firewater system. The diesel firewater pump engine will be limited to less than one hour per week for routine testing, maintenance, and inspection purposes only, with annual hours of operation limited to 52 hrs/yr. Combustion of diesel fuel will result in emissions of CO_2, CH_4, and N_2O.

GHG emissions are estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule (MRR). See Appendix B for detailed emission calculations.

$$CO_2, CH_4 \text{ or } N_2O = 1 \times 10^{-3} * \text{Fuel} * \text{HHV} * \text{EF} \qquad \text{... Eq. C-1 \& C-8}$$

Where each parameter is defined and further discussed below.

Parameter	Description	Remarks
CO_2 , CH_4, or N_2O	Annual CO_2, CH_4, or N_2O mass emissions (metric tons/year)	
Fuel	Maximum Potential Diesel Usage per year (scf/yr)	[Rated Capacity (MMBtu/hr) * 100 hours/yr Potential Operation] / (Diesel HHV)
HHV	Default high heat value of the fuel, from Table C-1 of this subpart (MMBtu/scf)	0.138 MMBtu/gal
EF	Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/MMBtu) OR Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 of this subpart (kg CH_4 or N_2O per MMBtu).	73.96 kg CO_2/MMBtu 0.003 kg CH_4/MMBtu 0.0006 kg N_20/MMBtu

7.3. CIRCUIT BREAKER SF_6 EMISSIONS

The proposed project will use approximately 34 circuit breakers on site which contain sulfur hexafluoride (SF_6). There is expected to be minimal SF_6 leakage in to the atmosphere. SF_6 fugitive emissions (EPN: CTBR-SF_6) are calculated as follows:

Annual Emission Rate (metric tpy) =
(Amount of SF_6 in Full Charge (lb)) x (SF_6 Leak Rate (%/yr)) x (1/2204.623 (metric ton/lb))

A worst-case leak rate of 0.5% per year was used from EPA's technical paper titled, "SF_6 Leak Rates from High Voltage Circuit Breakers - EPA Investigates Potential Greenhouse Gas Emission Source - by J. Blackman, Program Manager, EPA and M. Averyt, ICF Consulting, and Z. Taylor, ICF Consulting". See Appendix B for detailed emission calculations.

7.4. FUGITIVE EMISSIONS FROM PIPING COMPONENTS

Fugitive emissions of CH_4 are produced by equipment leaks from components in natural gas service (EPN: FUG-1). The controlled CH_4 emissions are calculated using the methodology and emission factors obtained from Table 2 for Oil and Gas Production Operations from Addendum to RG-360, Emission Factors for Equipment Leak Fugitive Components, TCEQ, January 2005, gas factors. The Montana Power Station will implement an Audio/Visual/Olfactory (AVO) program to reduce emissions from equipment leaks, with corresponding control efficiencies applied to the equipment leak fugitive calculations. See Appendix B for detailed emission calculations. Fugitive emissions from these components are estimated as follows:

Annual Emission Rate (metric tpy) =

(Component Count) x (Emission Factor (lb/hr-component)) x (1- AVO control efficiency) x (Methane Content (%)) x (Annual Hours of Operation (8,760 hrs/yr)) x (1/2204.623 (metric ton/lb))

These are described in further detail below:

Component	Maximum Count	Emission Factor (lb/hr-component)	AVO Control Efficiency	Source
Valves	106	0.00992	97%	Oil and Gas Production Operations from Addendum to RG-360, Emission Factors for Equipment Leak Fugitive Components, TCEQ, January 2005, Gas factors (Table 2)
Pressure Relief Valves	0	0.0194	97%	
Flanges	86	0.000860	97%	
Pumps	0	0.0194	93%	
Open-ended Lines	0	0.00441	97%	
Connectors	0	0.000440	97%	

8. EMISSION POINT SUMMARY (TCEQ TABLE 1(A))

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	**April 2012**	**Permit No.:**	**TBD**	**Regulated Entity No.:**	**TBD**
Area Name:	**Montana Power Station**			**Customer Reference No.:**	**CN600352819**

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) Pound Per Hour**	**(B) TPY**
FWP-1	FWP-1	Fire Water Pump	CH_4	0.01	<0.01
			N_2O	<0.01	<0.01
			CO_2	333.02	7.85
			CO_2e	334.14	7.88
GT-1	GT-1	Combustion Turbine 1	CH_4 (normal Operations)	1.89	5.00
			CH_4 (MSS Operations)	1.87	
			N_2O	0.19	0.43
			CO_2	100355.15	227601.61
			CO_2e	100453.57	227839.65
GT-2	GT-2	Combustion Turbine 2	CH_4 (normal Operations)	1.89	5.00
			CH_4 (MSS Operations)	1.87	
			N_2O	0.19	0.43
			CO_2	100355.15	227601.61
			CO_2e	100453.57	227839.65
GT-3	GT-3	Combustion Turbine 3	CH_4 (normal Operations)	1.89	5.00
			CH_4 (MSS Operations)	1.87	
			N_2O	0.19	0.43
			CO_2	100355.15	227601.61
			CO_2e	100453.57	227839.65
GT-4	GT-4	Combustion Turbine 4	CH_4 (normal Operations)	1.89	5.00
			CH_4 (MSS Operations)	1.87	
			N_2O	0.19	0.43
			CO_2	100355.15	227601.61
			CO_2e	100453.57	227839.65
CTBR-SF6	CTBR-SF6	Fugitive SF6 Circuit Breaker Emissions	SF_6	<0.01	0.01
			CO_2e	0.04	334.98
FUG-1	FUG-1	Components Fugitive Leak Emissions	CH_4	<0.01	0.13
			CO_2e	<0.01	2.81

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	April 2012	Permit No.:	TBD	Regulated Entity No.:	TBD
Area Name:	Montana Power Station			Customer Reference No.:	CN600352819

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building	6. Height Above	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	Ground (Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
GT-1	GT-1	Combustion Turbine 1	13	385,430	3,521,507		92.00	13.5	75.36 - 113.22	746.30 - 816.00			
GT-2	GT-2	Combustion Turbine 2	13	385,354	3,521,508		92.00	13.5	75.36 - 113.22	746.30 - 816.00			
GT-3	GT-3	Combustion Turbine 3	13	385,278	3,521,509		92.00	13.5	75.36 - 113.22	746.30 - 816.00			
GT-4	GT-4	Combustion Turbine 4	13	385,202	3,521,511		92.00	13.5	75.36 - 113.22	746.30 - 816.00			
FWP-1	FWP-1	Firewater Pump Engine	13	385,277	3,521,455	9.0	13.00	0.5	158.48	842.00			
FUG-1	FUG-1	Components Fugitive Leak	13	385,312	3,521,503		--	--	--	Ambient	72	43	0
CTBR-SF6	CTBR-SF6	Fugitive SF6 Circuit Breake	13	385,312	3,521,503		--	--	--	Ambient	TBD	TBD	TBD

EPN = Emission Point Number
FIN = Facility Identification Number

9. FEDERAL REGULATORY REQUIREMENTS

This section addresses the applicability of the following parts of 40 CFR for the equipment at the proposed Montana Power Station:

- Prevention of Significant Deterioration (PSD) in 40 CFR Section 52.21;
- New Source Performance Standards (NSPS) in 40 CFR Part 60;
- National Emissions Standards for Hazardous Air Pollutants (NESHAP) in 40 CFR Part 61; and
- NESHAP in 40 CFR Part 63, i.e., Maximum Available Control Technology (MACT) rules.

9.1. PSD APPLICABILITY REVIEW

A stationary source is considered “major” for PSD if it has the potential to emit either (1) 100 tpy or more of a regulated pollutant if the source is classified as one of 28 designated industrial source categories, or (2) 250 tpy or more of any regulated pollutant for unlisted sources. Combustion turbines alone are not on the List of 28 designated source categories and therefore, the major source threshold is 250 tpy.

The potential emissions from criteria pollutants do not exceed 250 tpy; however, the Montana Power Station is a major source of GHGs with respect to PSD permitting requirements (i.e., CO_2e emissions greater than 100,000 tpy). According to EPA guidance, the "major for one, major for all" PSD policy applies to GHGs for any project occurring on or after July 1, 2011. Therefore, if a greenfield site is major for GHGs only, then the criteria pollutant emissions need to be compared to the SERs (SERs; i.e., 40 tpy for NO_x, SO_2, and VOC, 100 tpy for CO, 25 tpy for PM, 15 tpy for PM_{10}, and 10 tpy for $PM_{2.5}$) when determining PSD applicability for these pollutants.

The proposed potential source-wide emissions of all federally regulated NSR pollutants are compared to the applicable PSD SERs in Table 9.1.

Table 9.1. Proposed Potential Emissions Compared with PSD SERs

Federally Regulated NSR Pollutant [1]	PSD SER (tpy) [2]	Exceeds SER? (Yes/No)
CO	100	**Yes**
NO_X	40	**Yes**
SO_2	40	No
PM	25	**Yes**
PM_{10}	15	**Yes**
$PM_{2.5}$	10	**Yes**
VOC	40	No
H_2SO_4 Mist	7	No

1. Only those regulated PSD pollutants for which quantifiable emissions are expected due to this project are listed.
2. 40 CFR §52.21(b)(23)

The estimated GHG emissions from the proposed Montana Power Station are greater than 100,000 tpy on a CO_2e basis and will trigger the requirement for PSD permitting due to being a major source of GHG emissions. The proposed project will also result in a significant net emissions increase for CO, NO_X, PM, PM_{10}, and $PM_{2.5}$ emissions. Therefore, PSD requirements, including best available control technology (BACT), apply for GHGs and for CO, NO_X, PM, PM_{10}, and $PM_{2.5}$ emissions. EPEC will submit two separate, but parallel in time, applications; one to the TCEQ for authorization of its non-GHG emission increases in accordance with the PSD rules and this one to the EPA for authorization of its GHG emissions.

Under the PSD regulations, each new source or modified emission unit subject to PSD is required to undergo a Best Available Control Technology (BACT) review. The BACT requirements for GHG emissions from the Montana Power Station are addressed in Section 10 of this application.

9.2. NEW SOURCE PERFORMANCE STANDARDS

There are currently no New Source Performance Standards (NSPS) for GHGs. The criteria pollutant NSPS are addressed in the Criteria Pollutant PSD application submitted to the TCEQ under a separate cover.

9.3. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

There are currently no MACTs for GHGs. The criteria pollutant MACTs are addressed in the Criteria Pollutant PSD application submitted to the TCEQ under a separate cover.

10. BEST AVAILABLE CONTROL TECHNOLOGY

This section documents the assumptions, methodologies and conclusions of the Best Available Control Technology (BACT) analysis undertaken to determine the BACT based limits on greenhouse gas (GHG) emissions from the proposed emission units.

10.1. BACT DEFINITION

The requirement to conduct a BACT analysis is set forth in the PSD regulation at 40 CFR § 52.21(j)(2):

(j) Control Technology Review. ...

(2) A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.

BACT is defined in the PSD regulations at 40 CFR § 52.21(b)(12)(emphasis added) as follows:

...an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61.

Differences in the characteristics of criteria pollutant and GHG emissions from large industrial sources present several GHG-specific considerations under the BACT definition which warrant further discussion. Those underlined terms in the BACT definition are addressed further below.

10.1.1. Emission Limitation

BACT is "an emission limitation," not an emission reduction rate or a specific technology. While BACT is predicated upon the application of technologies reflecting the maximum reduction rate achievable, the final result of a BACT determination is an emission limit. Typically, when quantifiable and measurable, this limit would be expressed as an emission rate limit of a pollutant (e.g., lb/MMBtu, ppm, or lb/hr). [3, 4] Furthermore, EPA's guidance on GHG BACT has indicated that GHG BACT limitations should be averaged over long-term timeframes such as a 30- or 365-day rolling average.[5]

10.1.2. Each Pollutant

Because BACT applies to "each pollutant subject to regulation under the Act," the BACT evaluation process is typically conducted for each regulated NSR pollutant individually and not for a combination of pollutants.[6] For PSD applicability assessments involving GHGs, the regulated NSR pollutant subject to regulation under the Clean Air Act (CAA) is the sum of six greenhouse gases and not a single pollutant. In the final Tailoring Rule preamble, EPA made

[3] The definition of BACT allows use of a work practice where emissions are not easily measured or enforceable. 40 CFR §52.21(b)(12).

[4] Emission limits can be broadly differentiated as "rate-based" or "mass-based." For a turbine, a rate-based limit would typically be in units of lb/MMBtu (mass emissions per unit of heat input). In contrast, a typical mass-based limit would be in units of lb/hr (mass emissions per unit of time).

[5] US EPA,, *PSD and Title V Permitting Guidance for Greenhouse Gases*. EPA-457/B-11-001 (Mar. 2011), page 46 (hereinafter "2011 Guidance")

[6] 40 CFR §52.21(b)(12)

clear that this combined pollutant approach for GHGs did not apply just to PSD applicability determinations but also to PSD BACT determinations, such that applicants should conduct a single GHG BACT evaluation on a CO_2e basis for emission sources that emit more than one GHG pollutant:

> *However, we disagree with the commenter's ultimate conclusion that BACT will be required for each constituent gas rather than for the regulated pollutant, which is defined as the combination of the six well-mixed GHGs. To the contrary, we believe that, in combination with the sum-of-six gases approach described above, the use of the CO_2e metric will enable the implementation of flexible approaches to design and implement mitigation and control strategies that look across all six of the constituent gases comprising the air pollutant (e.g., flexibility to account for the benefits of certain CH_4 control options, even though those options may increase CO_2). Moreover, we believe that the CO_2e metric is the best way to achieve this goal because it allows for tradeoffs among the constituent gases to be evaluated using a common currency.*[7]

EPEC acknowledges the potential benefits of conducting a single GHG BACT evaluation on a CO_2e basis for the purposes of addressing potential tradeoffs among constituent gases for certain types of emission units. However, for the proposed Montana Power Station, the GHG emissions are predominated by CO_2. CO_2 emissions represent more than 99% of the total CO_2e for the project as a whole. As such, the following top-down GHG BACT analysis should and will focus on CO_2.

10.1.3. BACT Applies to the Proposed Source

The applicant defines the proposed source (i.e., its goals, aims, and objectives). BACT applies to the type of source proposed by the applicant. Accordingly, EPA's GHG Permitting Guidance states that applicants need not identify control options that fundamentally redefine the source or the applicant's purpose.[8] EPEC has provided substantial project discussion in Appendix A of this report to aid the technical reviewers to understand the scope of this project and how GHG BACT should be reviewed in light of this detailed information.

10.1.4. Case-by-Case Basis

The PSD program's BACT evaluation is case-by-case. In 1990, EPA issued a Draft Manual on New Source Review permitting, which included a "top-down" BACT analysis, to assist applicants and regulators with this case-by-case process.

> *In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent--or "top"--alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.* [9]

The five steps in a top-down BACT evaluation can be summarized as follows:

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[7] 75 FR 31,531, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule*, June 3, 2010.

[8] "EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility." 2011 Guidance, page 26

[9] Draft NSR Manual at B-2. "The NSR Manual has been used as a guidance document in conjunction with new source review workshops and training, and as a guide for state and federal permitting officials with respect to PSD requirements and policy. Although it is not binding Agency regulation, the NSR Manual has been looked to by this Board as a statement of the Agency's thinking on certain PSD issues. E.g., *In re RockGen Energy Ctr.*, 8 E.A.D. 536, 542 n. 10 (EAB 1999), *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 129 n. 13 (EAB 1999)." *In re Prairie State Generating Company* 13 E.A.D. 1, 13 n 2 (2006)

Step 1. Identify all available control technologies;
Step 2. Eliminate technically infeasible options;
Step 3. Rank the technically feasible control technologies by control effectiveness;
Step 4. Evaluate most effective controls; and
Step 5. Select BACT.

While this EPA-recommended five step process can be directly applied to GHGs without any significant modifications, it is important to note that the top-down process is conducted on a unit-by-unit, pollutant-by-pollutant basis and only considers the portions of the facility that are considered “emission units” as defined under the PSD regulations.[10]

10.1.5. Achievable

BACT is to be set at the lowest value that is “achievable.” However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life. As discussed by the D.C. Circuit Court of Appeals:

> *In where a statute requires that a standard be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur."* [11]

EPA has reached similar conclusions in prior determinations for PSD permits.

> *Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured ‘emissions rates,’ which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the ‘emissions limitation’ determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility’s life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the “emissions limitation” that is “achievable” for that pollution control method over the life of the facility. Accordingly, because the “emissions limitation” is applicable for the facility’s life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term*.[12]

Thus, BACT must be set recognizing that compliance with that limit must be achievable for the lifetime of the facility on a continuous basis. While viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life.

To assist in meeting the BACT limit, the source must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source.

10.1.6. Production Process

The definition of BACT lists both production processes and control technologies as possible means for reducing emissions.

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[10] Pursuant to 40 CFR §52.21(a)(7), emission unit means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant.

[11] *Sierra Club v. U.S. EPA*, 167 F.3d 658 (D.C. Cir. 1999), quoting. *National Lime Ass'n v. EPA,* 627 F.2d 416, 431 n.46 (D.C. Cir. 1980).

[12] EPA Environmental Appeals Board decision, *In re: Newmont Nevada Energy Investment L.L.C.* PSD Appeal No. 05-04, decided December 21, 2005. Environmental Administrative Decisions, Volume 12, Page 442.

10.1.7. Available

The term "available" in the definition of BACT is implemented through a feasibility analysis – a determination that the technology being evaluated is demonstrated or available and applicable.

10.1.8. Floor

For criteria pollutants, the least stringent emission rate allowable for BACT is any applicable limit under either New Source Performance Standards (NSPS – Part 60) or National Emission Standards for Hazardous Air Pollutants (NESHAP – Parts 61). Since no GHG limits have been incorporated into any existing NSPS or Part 61 NESHAPs, no floor for a GHG BACT analysis is available for consideration.

On March 27, 2012, the EPA Administrator signed proposed Standards of Performance for GHG Emissions for Electric Utility Generating Units by adding Subpart TTTT to 40 CFR Part 60 (NSPS Subpart TTTT). EPA proposed an emission limit of 1,000 lbs CO_2/MWh, on a 12-month annual average for all electric generating units that did not employ CCS technology. However, per proposed 40 CFR 60.5520(d), simple cycle combustion turbines are not subject to the proposed NSPS Subpart TTTT. As of the date of this application, EPA has not finalized any NSPS or NESHAP GHG floor for consideration in a GHG BACT analysis. Additionally, EPA has not even proposed an NSPS GHG floor for SCCT technology.

10.2. GHG BACT ASSESSMENT METHODOLOGY

GHG BACT for the proposed project has been evaluated via a "top-down" approach, which includes the steps outlined in the following subsections.

It should be noted that EPA clarified the scope of a GHG BACT review in two ways:

> EPA stressed that applicants should clearly define the scope of the project being reviewed. EPEC has provided this information in Appendix A of this application.[13]
> EPA clarified that the BACT analysis should focus on the project's largest contributors to CO_2e and may subject less significant contributors for CO_2e to less stringent BACT review. Because the project's GHG emissions are predominated by the four natural gas SCCTs, this BACT analysis focuses mainly on these predominant sources of CO_2e from the project.

10.2.1. Step 0 - Define the Project

Historical practice, as well as recent court rulings, has been clear that a key foundation of the BACT process is that BACT applies to the type of source proposed by the applicant, and that redefining the source is not appropriate in a BACT determination.

Though BACT is based on the type of source as proposed by the applicant, the scope of the applicant's ability to define the source is not absolute. As EPA notes, a key task for the reviewing agency is to determine which parts of the proposed process are inherent to the applicant's purpose and which parts may be changed without changing that purpose. As discussed by EPA in an opinion on the Prairie State PSD project,

We find it significant that all parties here, including Petitioners, agree that Congress intended the permit applicant to have the prerogative to define certain aspects of the proposed facility that may not be redesigned through application of BACT and that other aspects must remain open to redesign through application of BACT.[14]

…

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[13] *2011 Guidance*, pages 22-23.
[14] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 26.

When the Administrator first developed [EPA's policy against redefining the source] *in Pennsauken, the Administrator concluded that permit conditions defining the emissions control systems "are imposed on the source as the applicant has defined it" and that "the source itself is not a condition of the permit.*[15]

Given that some parts of the project are not open for review under BACT, EPA then discusses that it is the permit reviewer's burden to define the boundary. Based on precedent set in multiple prior EPA rulings (e.g., Pennsauken County Resource Recovery [1988], Old Dominion Electric Coop [1992], Spokane Regional Waste to Energy [1989]), EPA states the following in the Prairie State PSD Appeal:

For these reasons, we conclude that the permit issuer appropriately looks to how the applicant, in proposing the facility, defines the goals, objectives, purpose, or basic design for the proposed facility. Thus, the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore, the permit issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility. [16]

EPA's opinion in Prairie State was upheld on appeal to the Seventh Circuit Court of Appeals, where the court affirmed the substantial deference due the permitting authority on defining the demarcation point.[17] Taken as a whole, the permitting agency is tasked with determining which controls are appropriate, but the discretion of the agency does not extend to a point requiring the applicant to redefine the source. As such, it is imperative for EPEC to include a discussion under "Step 0" of the GHG BACT Assessment Methodology as to what actually constitutes the proposed project. Please refer Appendix A for what constitute the scope of the proposed project.

10.2.2. Step 1 - Identify All Available Control Technologies

Available control technologies for CO_2e with the practical potential for application to the emission unit are identified under Step 1. The application of demonstrated control technologies in other source categories similar to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts, control technologies with potential application to the emission unit under review are identified in this step.

Under Step 1 of a criteria pollutant BACT analysis, the following resources are typically consulted when identifying potential technologies:

1. EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;
2. Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies;
3. Engineering experience with similar control applications;
4. Information provided by air pollution control equipment vendors with significant market share in the industry; and/or
5. Review of literature from industrial technical or trade organizations.

[15] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 29.

[16] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 30. See also EPA Environmental Appeals Board decision, *In re: Desert Rock Energy Company LLC*. PSD Appeal Nos. 08-03, 08-04, 08-05 & 08-06, decided Sept. 24, 2009, page 64 ("The Board articulated the proper test to be used to [assess whether a technology redefines the source] in *Prairie State*.").

[17] *Sierra Club v. EPA and Prairie State Generating Company LLC*, Seventh Circuit Court of Appeals, No. 06-3907, August 24, 2007. Rehearing denied October 11, 2007.

However, since GHG BACT is a new requirement, the RBLC database search only returned one result for GHGs from a SCCT, and this turbine was used at a natural gas processing plant. As such, EPEC will primarily rely on items (2) through (5) listed above and information from the EPA BACT GHG Work Group for data to establish BACT.

Additionally, EPA's GHG BACT requirements suggest that carbon capture and sequestration (CCS) be evaluated as an available control for substantial, large projects such as steel mills, refineries, and cement plants where CO_2e emissions levels are in the order of 1,000,000 tpy CO_2e, or for industrial facilities with high-purity CO_2 streams. Although the proposed Montana Power Station emissions are below 1,000,000 tpy CO_2e; EPEC has included a CCS evaluation as part of this BACT analysis.

10.2.3. Step 2 - Eliminate Technically Infeasible Options

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling GHG emissions from the source in question. The first question in determining whether or not a technology is feasible is whether or not it is demonstrated. If so, it is deemed feasible. Whether or not a control technology is demonstrated is considered to be a relatively straightforward determination.

> Demonstrated "means that it has been installed and operated successfully elsewhere on a similar facility." *Prairie State*, slip op. at 45. "This step should be straightforward for control technologies that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible."[18]

An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available".[19] Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative. The NSR Manual explains the concept of applicability as follows: "An available technology is 'applicable' if it can reasonably be installed and operated on the source type under consideration."[20] Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual.

10.2.4. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

All remaining technically feasible control options are ranked based on their overall control effectiveness for GHG. For GHGs, this ranking may be based on energy efficiency and/or emission rate.

10.2.5. Step 4 - Evaluate Most Effective Controls and Document Results

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration, it is selected as the basis for the BACT limit. Alternatively, in the judgment of the permitting agency, if unreasonable adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified.

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[18] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.17.

[19] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

[20] Ibid.

The energy, environment, and economic impacts analysis under Step 4 of a GHG BACT assessment presents a unique challenge with respect to the evaluation of CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a proportional increase in emissions of another GHG (i.e., CO_2). However, since the Global Warming Potential (GWP) of CH_4 is 21 times higher than CO_2, conversion of CH_4 emissions to CO_2 results in a net reduction of CO_2e emissions.

Permitting authorities have historically considered the effects of multiple pollutants in the application of BACT as part of the PSD review process, including the environmental impacts of collateral emissions resulting from the implementation of emission control technologies. To clarify the permitting agency's expectations with respect to the BACT evaluation process, states have sometimes prioritized the reduction of one pollutant above another. For example, technologies historically used to control NO_X emissions frequently caused increases in CO emissions. Accordingly, several states prioritized the reduction of NO_X emissions above the reduction of CO emissions, approving low NO_X control strategies as BACT that result in higher CO emissions relative to the uncontrolled emissions scenario.

10.2.6. Step 5 - Select BACT

In the final step, the BACT emission limit is determined for each emission unit under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology. BACT is an emission limit unless technological or economic limitations of the measurement methodology would make the imposition of an emissions standard infeasible, in which case a work practice or operating standard can be imposed.

Establishing an appropriate averaging period for the BACT limit is a key consideration under Step 5 of the BACT process. Localized GHG emissions are not known to cause adverse public health or environmental impacts. Rather, EPA has determined that GHG emissions are anticipated to contribute to long-term environmental consequences on a global scale. Accordingly, EPA's Climate Change Work Group has characterized the category of regulated GHGs as a "global pollutant." Given the global nature of impacts from GHG emissions, National Ambient Air Quality Standards (NAAQS) are not established for GHGs and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs. Since localized short-term health and environmental effects from GHG emissions are not recognized, EPEC proposes only an annual average GHG BACT limit.

10.3. GHG BACT REQUIREMENT

The GHG BACT requirement applies to each new emission unit for which the calculated GHG emissions are subject to PSD review. The proposed Montana Power Station is a new major source with respect to GHG. The estimated GHG emissions from the proposed facility will be greater than 100,000 tpy on a CO_2e basis primarily due to the combustion of natural gas in the four turbines.

Potential emissions of GHGs from the proposed Montana Power Station will result from the following emission units:

- Four combustion turbines (EPNs: GT-1, GT-2, GT-3, GT-4);
- MSS Emissions from the combustion turbines (EPNs: GT-1-MSS, GT-2-MSS, GT-3-MSS, and GT-4-MSS)
- One fire water pump (EPN: FWP-1);
- Fugitive emissions from piping components (EPN: FUG-1); and
- Fugitive emissions from SF_6 circuit breakers (EPN: CTBR-SF_6).

This BACT analysis focuses mainly on the predominant sources of CO_2e from the project (e.g., the four combustion turbines). GHG emissions from small emission sources such as the fire water pump, MSS activities, circuit breaker equipment leaks, and piping component leaks are included in the BACT analysis as well.

The emission calculations provided in Appendix B include a summary of the estimated maximum annual potential to emit GHG emission rates for the proposed Montana Power Station. GHG emissions for each emission unit are estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Gas Reporting Rule (40 CFR 98, Subpart C).

The following guidance documents were utilized as resources in completing the GHG BACT evaluation for the proposed project:

1. PSD and Title V Permitting Guidance For Greenhouse Gases (hereafter referred to as General GHG Permitting Guidance)[21]
2. Report of the Interagency Task Force on Carbon Capture & Storage (hereafter referred to as CCS Task Force Report)[22]

10.4. GHG BACT EVALUATION FOR PROPOSED EMISSION SOURCES

The following is an analysis of BACT for the control of GHG emissions from the proposed Montana Power Station following the EPA's five-step "top-down" BACT process. The table at the end of this section summarizes each step of the BACT analysis for the emission units included in this review. EPEC is proposing the use of good combustion practices for the stationary combustion sources at the proposed facility.

Table 10.1 provides a summary of the proposed BACT limits discussed in the following sections.

Table 10.1. Proposed GHG BACT Limits for the Montana Power Station

EPN	Description	Proposed BACT Limit[a,b] (CO_2e tpy)
GT-1	Combustion Turbine 1	227,840
GT-2	Combustion Turbine 2	227,840
GT-3	Combustion Turbine 3	227,840
GT-4	Combustion Turbine 4	227,840
FWP-1	Fire Water Pump	8
FUG-1	Fugitive emissions from piping components	94
CTBR-SF_6	SF_6 circuit breaker equipment leaks	335

[a] The BACT limit for the Combustion Turbines includes MSS emissions
[b] The BACT limits are represented in metric tons

A detailed BACT analysis is conducted for the four combustion turbines, MSS emissions from the combustion turbines, the fire water pump, fugitive emissions from piping components, and the circuit breaker equipment leaks.

[21] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: March 2011). http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf
[22] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf

10.5. OVERALL PROJECT ENERGY EFFICIENCY CONSIDERATIONS

While the five-step BACT analysis is the EPA's preferred methodology with respect to selection of control technologies for pollutants, EPA has also indicated that an overarching evaluation of energy efficiency should take place as increases in energy efficiency will inherently reduce the total amount of GHG emissions produced by the source. As such, overall energy efficiency was a basic design criterion in the selection of technologies and processing alternatives to be installed at the proposed Montana Power Station. The new 400 MW electric generating station will be designed and constructed using all new, energy efficient equipment.

10.6. COMBUSTION TURBINES

GHG emissions from the proposed combustion turbines include CO_2, CH_4, and N_2O and result from the combustion of natural gas. The following section presents a GHG BACT evaluation for the proposed SCCTs.

10.6.1. Step 0 - Define the Project

As described in Appendix A of this report, EPEC's primary objective in pursuing the proposed project is to construct a Peaking Electric Generating Station that will be used during periods of high demand. Due to the need to respond quickly to fluctuations in power requirements, the selected turbines must have a fast ramp rate. Compared with SCCTs, CCCTs simply have slower ramp rates and are designed for intermediate load and baseload operations. Per a recent SCCT application for a peaking plant submitted to the California Energy Commission (CEC), the CEC noted the following in a February 2012 Preliminary Staff Assessment:

"the combined cycle CTG [combustion turbine generator] *alternative does not meet the project's "quick start" objective which is presumed to be a startup time of no more than 15-minutes and ideally less than 10-minutes. … it is not a feasible alternative to the proposed simple-cycle combustion turbine because the combined-cycle technology cannot meet a key project objective – to provide quick start capability for peak demand periods and to mitigate for grid instability caused by the intermittency of renewable energy generation."* [23]

In line with very recent conclusions from regulatory agencies, EPEC concludes that a CCCT simply cannot meet the needs of the proposed project scope. The use of any type of turbine other than simple cycle will not be discussed as a BACT option as this is clearly outside the scope of the proposed project. Please refer to Appendix A for additional information on the project scope.

10.6.2. Step 1 – Identify All Available Control Technologies

The available GHG emission control strategies for SCCTs that are analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration,
- Evaporative Cooling,
- Selection of Efficient SCCT,
- Fuel Selection,
- Good Combustion, Operating, and Maintenance Practices.

EPA's "top-down" BACT analysis procedure also recommends the consideration of inherently lower emitting processes as available control options under Step 1. For GHG BACT analyses, low-carbon intensity fuel selection is the primary control option that can be considered a lower emitting process. EPEC proposes the use of pipeline quality natural gas as the sole fuel source for the four SCCTs being proposed as part of this project. Table C-1 of 40 CFR Part 98 shows CO_2 emissions per unit heat input (MMBtu) for a wide variety of industrial fuel types. Only biogas (captured methane) and coke oven gas result in lower CO_2 emissions per unit heat input than natural gas. Biogas and coke oven gas are not available in the EPEC service area.

[23] http://www.energy.ca.gov/2012publications/CEC-700-2012-002/CEC-700-2012-002-PSA.pdf, February 2012, pages 6-19 and 6-20.

10.6.2.1. *Carbon Capture and Sequestration*

CCS involves "capturing" the CO_2 from the exhaust of the emission source, transporting the CO_2 to an appropriate injection site, and then storing CO_2 at a suitable sequestration site. The following sections describe the technical feasibility of each of the three steps necessary for the successful implementation of CCS.

10.6.2.1.1. CO_2 Capture

CCS would involve post combustion capture of the CO_2 from the combustion turbines and sequestration of the CO_2 in some fashion. Carbon capture is an established process in some industry sectors, although not in the natural gas power generation sector in baseload, peaker, or full stream applications. In theory, carbon capture could be accomplished with low pressure scrubbing of CO_2 from the exhaust stream with either solvents (e.g., amines and ammonia), solid sorbents, or membranes. However, only solvents have been used to-date on a commercial (yet slip stream) scale, and solid sorbents and membranes are only in the research and development phase.

In terms of post combustion CCS for power plants, the following six projects have taken place on slip streams at coal-fired power plants:[24, 25]

1. *AEP Mountaineer* (Sept. 2009- May 2011): AEP conducted a post-combustion CO_2 capture using Alstom's chilled ammonia process to capture 50,000 tonnes CO_2 during the September 2009 to May 2011 time period on a 20 MW_e slipstream from the exhaust of its 1,300 MW coal-fired Mountaineer plant in New Haven, West Virginia. The captured CO_2 is sequestered in deep geologic formations beneath the Mountaineer site.[26 27,28]
2. *First Energy R.E. Burger* (Dec. 2008-Dec. 2010): First Energy conducted a CO_2 capture pilot test using Powerspan's ECO_2® technology on a 1 MWe slipstream from the outlet of the R.E. Burger Station (near Shadyside, Ohio) demonstration-scale 50 MW ECO unit (Powerspan's multipollutant control system). The ECO system is designed to control SO_2, NO_X, oxidized mercury, and fine particulate matter from an 110,000 scfm slipstream of a 156 MW coal boiler. The ECO_2® CO_2 capture system uses a proprietary ammonia-based solvent in a thermal swing absorption (TSA) process to remove CO_2 from the flue gas. The project handles 25 tpd dried, compressed, and sequestration-ready CO_2, but the literature does not suggest the CO_2 is permanently sequestered in any geologic formation or by any other means. An independent review of the pilot test indicated that "technology is ready for scale-up for use in commercial scale (200 MW or larger) generating plants." To date, this technology has not been scaled up to any known commercial scale operations.[29]
3. *AES Warrior Run* (2000-Present)*:* AES captures 110,000 tpy CO_2 using the ABB/Lummus monoethanolamine (MEA) solvent-based system from a small slipstream of the 180 MWe coal-fired circulating fluidized bed (CFB) power plant at its Warrior Run station in Cumberland, Maryland. The extracted CO_2 is used in the food processing industry and related processes.
4. *AES Shady Point* (1991-Present)*:* AES captures 66,000 tpy CO_2 using the ABB/Lummus' MEA technology from a small slipstream of a 320 MW coal-fired CFB boiler at its Shady Point station in Panama, Oklahoma. The extracted CO_2 is used for food processing, freezing, beverage production, and chilling purposes.
5. *IMC Chemicals (formerly Searles Valley Minerals)* (1978-Present)*:* IMC Chemicals captures 270,000 tpy CO_2 from the flue gas of two 52-56 MW industrial coal boilers using amine scrubbing technology at its soda ash

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[24] CCS Task Force Report, http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf, p. 31

[25] International Energy Agency GHG Research & Development Program, *RD&D Database: CO_2 Capture Commercial Projects*, http://www.ieaghg.org/index.php?/RDD-Database.html

[26] *Carbon Capture Journal*, "Alstom and AEP Commission Mountaineer CCS Demonstration", October 30, 2009, http://www.carboncapturejournal.com/displaynews.php?NewsID=475.

[27] MIT Carbon Capture & Sequestration Technologies, *AEP Alstom Mountaineer Fact Sheet: Carbon Dioxide Capture and Storage Project*, March 7, 2012, http://sequestration.mit.edu/tools/projects/aep_alstom_mountaineer.html.

[28] American Electric Power website, http://www.aep.com/environmental/climatechange/carboncapture/

[29] Powerspan, FirstEnergy ECO_2® Pilot Facility, http://powerspan.com/projects/firstenergy-eco2-pilot-facility/; http://powerspan.com/technology/eco2-co2-capture/independent-review-of-eco2/

production plant in Trona, California. The captured CO_2 is used for the carbonation of brine from Searles Lake, and the brine is subsequently used in the soda ash production process. [30]

6. *WE Energy Pleasant Prairie* (June 2008-Oct. 2009): WE Energy captured 15,000 tpy CO_2 using Alstom's chilled ammonia process from a 5 MW_e slipstream of the 1,210 MW coal-fired power plant at its Pleasant Prairie station in Pleasant Prairie, Wisconsin. The literature does not suggest the CO_2 was permanently sequestered in any geologic formation or by any other means.[31]

Although these projects have demonstrated the technical feasibility of small-scale CO_2 capture on a slipstream of a power plant's emissions using various solvent based scrubbing processes, until these post combustion technologies are installed fully on a power plant, they are not considered "available" in terms of BACT.

In addition to the coal fired power projects deploying CO_2 capture at a small scale, Florida Power & Light (FP&L) conducted CO_2 capture to produce 320-350 tpd CO_2 using the Fluor Econamine FG^{SM} scrubber system on 15 percent of the flue gas from its 320 MWe 2 x 1 natural gas combined cycle unit in Bellingham, Massachusetts from 1991 to 2005. Due to increases in natural gas prices in 2004-2005, FP&L changed from a base/intermediate load plant to a peaking plant, which made the continued operation of the capture plant uneconomical. The captured CO_2 was compressed and stored on site for sale to two nearby major food processing plants.[32, 33] Although this project indicates small-scale CO_2 capture is technically feasible for natural gas combined cycle (NGCC) flue gas, it does not support the availability of full-scale CO_2 capture in a SCCT peaking plant.

As discussed below, a number of larger scale CCS demonstration projects have been proposed through the DOE Clean Coal Power Initiative (CCPI).[34]

> *"CCPI is pursuing three pre-combustion and three post-combustion CO_2 capture demonstration projects using currently available technologies (see Appendix A, Table A-8) . . . The post-combustion projects will capture CO_2 from a portion of the PC plant's flue gas stream. The specific projects include the following:*
>
> - *Basin Electric: amine-based capture of 900,000 tonnes per year of CO_2 from a 120 MW equivalent slipstream at a North Dakota plant for use in an EOR application and/or saline storage.*
> - *NRG Energy: amine-based capture of 400,000 tonnes per year of CO_2 from a 60 MW equivalent slipstream at a Texas plant for use in an EOR application.*
> - *American Electric Power: ammonia-based capture of 1.5 million tonnes per year of CO_2 from a 235 MW equivalent slipstream at a West Virginia plant for saline storage."*

None of these facilities are operating, and, in fact, they have not yet been fully designed or constructed. Furthermore, American Electric Power recently announced that the CCS project has been put on hold due to the lack of federal carbon limits. [35] Finally, Tenaska is currently in the process of developing a 600 MWe generating plant fueled by pulverized coal near Sweetwater, Texas. Tenaska is planning to capture 85 to 90 percent of the CO_2 emitted from the plant using the Fluor Econamine FG Plussm (amine-based) technology, and sending the captured CO_2 to the Permian Basin for enhanced oil recovery.[36]

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[30] Electrical Power Research Institute, *CO_2 Capture and Storage Newsletter*, "Visit to the Trona plant MEA CO_2 Removal System in Trona, California, in September 2006", Issue #2 December 2006, http://mydocs.epri.com/docs/public/000000000001014698.pdf

[31] MIT Carbon Capture & Sequestration Technologies, *AEP Alstom Mountaineer Fact Sheet: Carbon Dioxide Capture and Storage Project*, November 23, 2011, http://sequestration.mit.edu/tools/projects/pleasant_prairie.html.

[32] International Energy Agency GHG Research & Development Program, *RD&D Database: Florida Light and Power Bellingham CO_2 Capture Commercial Project*, http://www.ieaghg.org/index.php?/RDD-Database.html.

[33] Reddy, Satish, et. al., Fluor's Econamine FG Plus^{SM} Technology for CO_2 Capture at Coal-fired Power Plants, Power Plant Air Pollutant Control "Mega" Symposium, August 25-28, 2008, Baltimore, Maryland, http://web.mit.edu/mitei/docs/reports/reddy-johnson-gilmartin.pdf.

[34] CCS Task Force Report, August 2010, p. 32.

[35] Sweet, Cassandra. *The Wall Street Journal.* "AEP Drops Carbon Storage Project On Lack Of Federal Carbon Limits". http://online.wsj.com/article/BT-CO-20110714-716173.html. July 14, 2011.

[36] Tenaska, July 26, 2010, http://www.tenaska.com/newsItem.aspx?id=82

The projects identified do not propose post combustion capture of CO_2 from a SCCT to be used in a peaking role. Rather they are for post combustion capture on a pulverized coal (PC) plants or a natural gas CCCT (in one case) using a slip stream versus the full exhaust stream. Also, the exhaust from a PC plant would have a significantly higher concentration of CO_2 in the slipstream as compared to a more dilute stream from the combustion of natural gas (approximately 13-15 percent for a coal fired system versus 3-4 percent for a natural-gas fired system).[37]

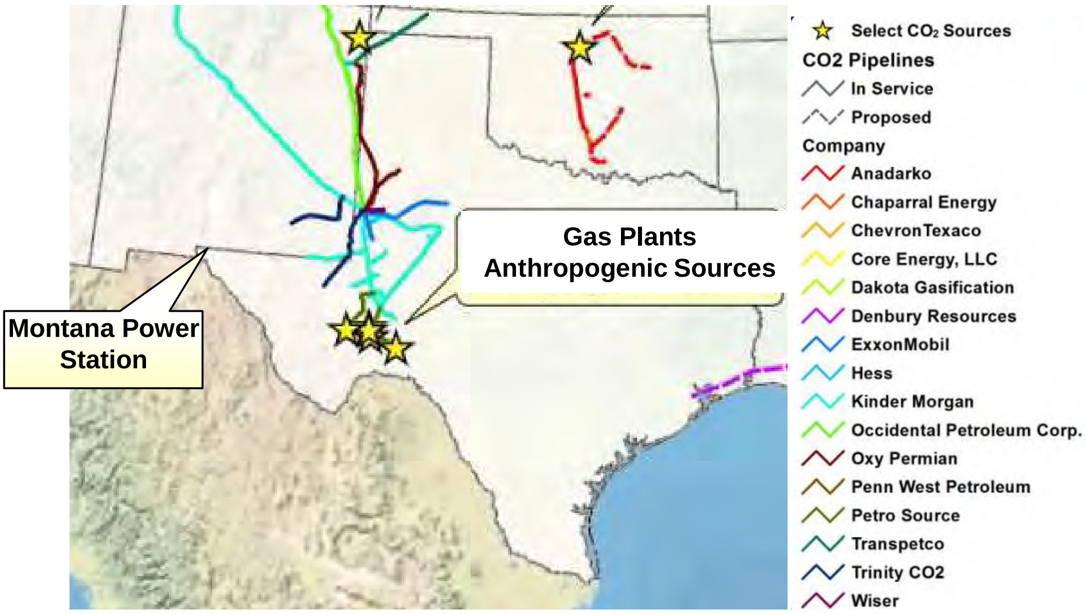
In addition, prior to sending the CO_2 stream to the appropriate sequestration site, it is necessary to compress the CO_2 from near atmospheric pressure to pipeline pressure (around 2,000 psia). The compression of the CO_2 would require a large auxiliary power load, resulting in additional fuel (and CO_2 emissions) to generate the same amount of power.[38]

While carbon capture technology may be technologically available on a small-scale, it has not been demonstrated in practice for full-scale natural gas peaker plants. CCS is not commercially available as BACT at present for the turbines given the limited deployment of only slipstream/demonstration applications of CCS.

10.6.2.1.2. CO_2 Transport

CO_2 capture has not been demonstrated in practice on a full size power plant and therefore not commercially available as BACT; furthermore, even if capture were demonstrated, sequestration of the captured CO_2 would pose its own barriers to the use of CCS as BACT. Accordingly, EPEC is including a discussion on the feasibility of transporting the CO_2 captured from the exhaust of the four SCCTs to an appropriate sequestration site. Either EPEC would need to transport the captured CO_2 to an existing CO_2 pipeline, or transport the CO_2 to a site with recognized potential for storage (e.g., enhanced oil recovery [EOR] sites). The closest potential sequestration site is approximately 110 miles from the proposed Montana Power Station. Refer to Figure 10.1 below for a map illustrating the distance from the proposed facility to the closest CO_2 pipeline and appropriate sequestration sites.

Figure 10.1. CO_2 Sources and Pipelines[39]



It is technically feasible to construct a CO_2 pipeline 110 miles to the closest potential sequestration site.

[37] CCS Task Force Report, August 2010, p. 29.
[38] CCS Task Force Report, August 2010, p. 30.
[39] This map is taken directly from CCS Task Force Report, p. B-1.

10.6.2.1.3. CO_2 Storage

The process of injecting CO_2 into subsurface formations for long-term sequestration is referred to as CO_2 storage. CO_2 can be stored underground in oil/gas fields, unmineable coal seams, and saline formation. In practice, CO_2 is currently injected into the ground for enhanced oil and gas recovery. Per the CCS Task Force Report, approximately 50 million tonnes of CO_2 per year are injected during enhanced oil and gas recovery operations.

Internationally, there are three large scale projects that are currently in operation worldwide as follows:[40]

1. The Sleipner Project (1996 – current): One million tonnes of CO_2 per year is separated from produced natural gas in Norway and is injected into Utsira Sand (high permeability, high porosity sandstone) 1,100 meters below the sea surface.
2. The Weyburn Project (2000 – 2011): 1.8 million tonnes of CO_2 per year is injected into 29 horizontal and vertical wells into two adjacent carbonate layers in Saskatchewan, Canada near the North Dakota border. The CO_2 originates from a nearby synfuel plant.[41]
3. The Snohvit Project (2010 – current): The project is expected to inject 0.7 million tonnes CO_2 per year from natural gas production operations near the Barents Sea. The injection well reaches 2,600 meters beneath the seabed in the Tubasen sandstone formation.
4. The In Salah Project (2004 – current): The project injects 1.2 million tonnes of CO_2 annually produced from natural gas into 1,800 meter deep muddy sandstone (low porosity, low permeability).

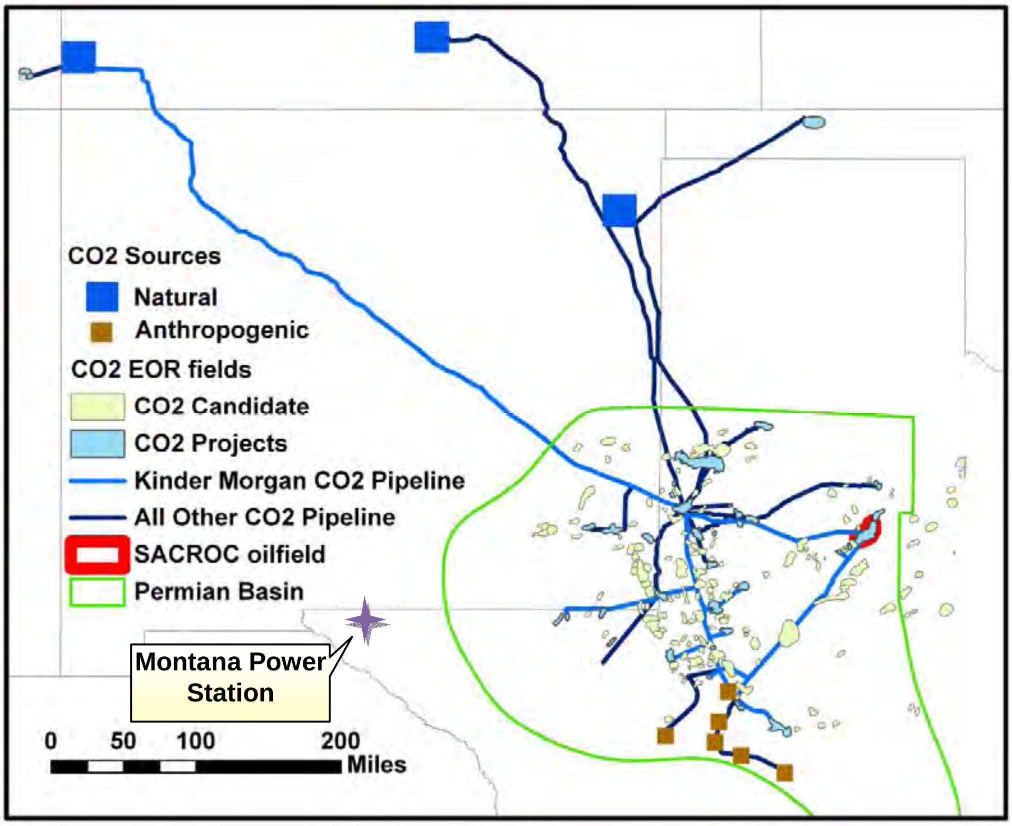
The Scurry Area Canyon Reed Operators (SACROC) oilfield is near the eastern edge of the Permian Basis in Scurry, Texas. Since 1974, over 175 million tonnes of CO_2 have been injected into the SACROC oilfield for EOR.[42] The SACROC oilfield is approximately 400 miles from the Montana Power Station. Figure 10.2 below provides a visual illustration of the proximity of the Montana Power Station to the SACROC oilfield.

[40] CCS Task Force Report, Pages C-1 and C-2.

[41] Petroleum Technology Research Centre, http://www.ptrc.ca/weyburn_overview.php

[42] Bureau of Economic Geology, SACROC Research Project, http://www.beg.utexas.edu/gccc/sacroc.php

Figure 10.2: SACROC Oil Field in Relation to the Montana Power Station[43]



For the purposes of this analysis, it is assumed that CO_2 storage is technically feasible option for EPEC to employ for CO_2 emissions from the Montana Power Station.

In conclusion, even though transporting and sequestering CO_2 is feasible, CCS is not a viable, technically feasible option for this project due to the fact that CO_2 capture has not been achieved in practice for a large scale, 360 MWe natural gas peaking plant. However, even with this technological infeasibility demonstration, EPEC is providing EPA with an economic feasibility assessment on why CCS is not a legitimate technology for use as GHG BACT on the SCCTs. Please refer to Appendix D below for the BACT economic assessment.

10.6.2.2. *Evaporative Cooling*

Evaporative cooling involves the cooling of gas turbine inlet air in order to increase combustion air mass flow. Air flows through a wetted medium and is cooled as some of the water evaporates off the wet media and into the inlet air. The evaporation process reduces the air temperature. Cooled air then passes through a mist eliminator to remove leftover water droplets, and is then directed into the turbine inlet. Cooling the combustion air increases the density and therefore results in a higher mass-flow rate and pressure ratio, resulting in increased turbine output and efficiency. The four SCCTs will employ evaporative cooling.

[43] Map obtained from the following website: http://www.beg.utexas.edu/gccc/sacroc.php

10.6.2.3. *Selection of Efficient SCCT*

EPEC conducted a comprehensive evaluation of the available SCCTs that could be installed at the proposed Montana Power Station. Table 10.2 below includes a comparison of the SCCTs evaluated based on the efficiency of the turbines (e.g., Btu input per MWh output). In general, GHG emissions are inversely proportional to heat rate.

Table 10.2. Commercially Available SCCTs

SCCT Description	Heat Rate (Btu/kW-hr)
GE LMS100 Wet/Wet	9,074
GE LMS100 Dry/Dry Hybrid	9,090
GE LMS100 Wet/Wet	9,299
Siemens 5000F	10,845

As Table 10.2 demonstrates, GE's LMS100 Wet/Wet configuration offers EPEC the lowest heat rate for the new Montana Power Station. As such, EPEC selects the LMS100 SCCT as the most efficient unit that meets the definition of the proposed project.

10.6.2.4. *Fuel Selection*

Natural gas has the lowest carbon intensity of any available fuel for the combustion turbines. The proposed combustion turbines will be fired with only natural gas fuel.

10.6.2.5. *Good Combustion, Operating, and Maintenance Practices*

Good combustion and operating practices are a potential control option by improving the fuel efficiency of the combustion turbines. Good combustion practices also include proper maintenance and tune-up of the combustion turbines at least annually per the manufacturer's specifications. EPEC will implement the following good combustion, operating, and maintenance practices on the four SCCTs:

Table 10.3. Good Combustion, Operating, and Maintenance Practices

Good Combustion Technique	Practice	Standard
Operator practices	• Official documented operating procedures, updated as required for equipment or practice change. • Procedures include startup, shutdown, malfunction • Operating logs/record keeping	• Maintain written site specific operating procedures in accordance with GCPs, including startup, shutdown, and malfunction.
Maintenance knowledge	• Training on applicable equipment & procedures.	• Equipment maintained by personnel with training specific to equipment.
Maintenance practices	• Official documented maintenance procedures, updated as required for equipment or practice change • Routinely scheduled evaluation, inspection, overhaul as appropriate for equipment involved • Maintenance logs/record keeping	• Maintain site specific procedures for best/optimum maintenance practices • Scheduled periodic evaluation, inspection, overhaul as appropriate.
Fuel quality analysis and fuel handling	• Monitor fuel quality • Fuel quality certification from supplier if needed • Periodic fuel sampling and analysis • Fuel handling practices • EPEC will use pipeline quality natural gas	• Fuel analysis where composition could vary • Fuel handling procedures applicable to the fuel.

10.6.3. Step 2 – Eliminate Technically Infeasible Options

As discussed above, CCS is deemed technically infeasible for control of GHG emissions from the combustion turbines. However, EPEC has decided to perform an economic feasibility analysis for the use of CCS on the CO_2 emissions from the four SCCTs. All other control options are technically feasible.

10.6.4. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

With elimination of CCS as a control option, the following remain as technically feasible control options for minimizing GHG emissions from the combustion turbines:

- Evaporative cooling;
- Selection of Efficient SCCTs;
- Fuel Selection; and
- Implementation of good combustion, operating, and maintenance practices.

Ranking the above control options is unnecessary because EPEC proposes to implement all of these control options.

10.6.5. Step 4 – Evaluate Most Effective of Control Options

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. For all identified technologically feasible control technologies except CCS, EPEC has not identified any adverse energy, environmental, or economic impacts.

As discussed in Sections 10.6.2 and 10.6.3, CCS is considered technically infeasible. However, EPEC has opted to include a cost feasibility assessment for use of CCS for completeness. The costs associated with CCS can be broken down into the same three categories that the CCS process is divided: CO_2 Capture, CO_2 Transport, and CO_2 Storage. The CCS cost estimation presented in this document is primarily based on cost factors obtained from the CCS Task Force Report. The cost analysis carried out in the CCS Task Force Report identifies a range of costs associated with each component of CCS (e.g., capture, transport, and storage). To be conservative, the lowest, most applicable factors are taken for use in the cost estimation presented herein. It should also be noted that for this analysis, the factors which appear in the CCS Task Force Report have been converted from a metric tons basis to a short tons basis and escalated from December 2009 dollars to February 2012 (current) dollars using appropriate price indices.[44] The original values as published in the CCS Task Force Report as well as the adjusted values are shown in Table 10.3 below.

Capture and compression costs vary widely depending on what type of combustion equipment and process is used at the facility. Of the power plant configurations for which cost factors are provided in the CCS Task Force Report, the factor for a new natural gas combined cycle facility is taken to be the most applicable. Capture and compression costs typically use either a "CO_2-Captured" or a "CO_2-Avoided" basis. The CO_2-captured basis accounts for all CO_2 that is removed from the process as a result of the installation and use of a control technology, without including any losses during transport and storage or emissions from the control technology itself. A CO_2-avoided basis takes into account the CO_2 losses during transport and storage as well as CO_2 emissions from equipment associated with the implementation of the CCS system. It is more appropriate to use the CO_2 captured monetary estimates because the BACT analysis is based on emissions from a single source (e.g., the direct emissions from the SCCTs) and does not account for secondary emissions (e.g., the GHG emissions generated from the act of compressing the CO_2 to pipeline pressures). As such, the cost factor which uses a CO_2-captured basis is selected for use in this analysis.

The CO_2 transport costs presented in the CCS Task Force Report (e.g., $1.00 per tonne CO_2) are based on a pipeline length of 100 km (62 miles). It is assumed that this factor may be linearly scaled up for longer pipeline lengths. The hypothetical length of a CO_2 pipeline associated with the proposed project is 110 miles. As such, the CO_2 transport cost factor from CCS Task Force Report has been adjusted upward proportionally for this consideration.

As presented in the CCS Task Force Report, the costs associated with storage of CO_2 show large variability. The CCS Task Force Report presents a cost range of $0.40 up to $20.00 per tonne of CO_2 stored. While a cost of forty cents per tonne may be an underestimation, it is conservatively taken as the appropriate cost factor for this cost estimate.

[44] Price indices for December 2009 and January 2012 are obtained from the Consumer Price Index published by the U.S. Bureau of Labor Statistics. CPI values obtained from historic tables. Accessed online 3/16/2012 at http://www.bls.gov/cpi/tables.htm.

Table 10.3. Cost Evaluation of CCS

Carbon Capture and Storage (CCS) Component	Approximate Cost Factors (ACF) ($/tonne CO_2 removed, 12/09 Dollars)	Adjusted ACF ($/ton CO_2 removed, 02/2012 Dollars)[1]	Basis
Capture - NGCC[2,3]	95.00	110.40	CO_2 Captured
Transport[2]	1.77	2.06	CO_2 Transported per 110 miles of pipeline
Storage[2,4]	0.40	0.46	CO_2 Stored
Total Cost For Capture, Transport, and Storage[5]	97.17	112.93	CO_2 Captured, Transported, and Stored

1. Cost Factors are converted from dollars per metric ton removed to dollars per short ton removed using a conversion factor of 1 metric ton = 1.1023 short tons. Monthly data from the Consumer Price Index (CPI) is used to convert December 2009 dollars (CPI = 215.949) to February 2012 dollars (CPI = 227.663).
2. ACF obtained from the CCS Task Force Report.
3. The cost factor for post-combustion capture of CO_2 from a NGCC system is selected because it is the most similar process with available cost information to that of the proposed project. Note that the ACF for capturing the CO_2 from the SCCTs also includes the cost for compressing the CO_2 for transport in pipelines.
4. Storage cost includes consideration for initial site screening and evaluation, operation of injection equipment, and post-injection site monitoring.
5. Total Cost for implementation of a CCS system equals the sum of the individual Capture, Transport, and Storage costs.

The original and adjusted cost factors as well as the overall estimated cost of CCS implementation at the Montana Power Station are shown in Table 10.3 above. The overall estimated cost of CCS implementation represents the sum of the individual cost factors. As shown in the table, the estimated cost of CCS implementation at the Montana Power Station is $112.93/ton removed of CO_2. As such, EPEC contends that CCS is both a technologically and economically infeasible control technology option and eliminates CCS from further review under this BACT analysis.

10.6.6. Step 5 – Select BACT for the SCCTs

EPEC proposes the following design elements and work practices as BACT for the combustion turbines:

- Evaporative cooling design;
- Installation of four LMS100 SCCTs;
- Use of natural gas as fuel; and
- Implementation of good combustion, operating, and maintenance practices.

EPEC proposes a CO_2e emission limit of 227,840 tpy CO_2e for each of the four SCCTs which includes emissions from MSS activities. The proposed emission limits is based on a 365-day rolling average basis and includes CO_2, CH_4, and N_2O emissions, with CO_2 emissions being more than 99% of the total emissions.

Compliance with these emission limits will be demonstrated by monitoring fuel consumption with a fuel flow meter, installing a CO_2 CEMS on each turbine stack, and performing CH_4 and N_2O calculations consistent with the calculations included in Appendix B of this application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average short tons of CO_2e per year emission rates do not exceed these limits.

10.7. FIREWATER PUMP

The proposed project will comprise of one 327-hp diesel fired firewater pump. The firewater pump will be limited to 52 hours of operation per year for purposes of maintenance and testing. CO_2 emissions from the diesel engine are produced from the combustion of hydrocarbons present in the diesel fuel. CH_4 emissions result from incomplete combustion of hydrocarbons present in the diesel fuel. N_2O emissions from diesel-fueled units form solely as a byproduct of combustion.

The following sections present a BACT evaluation of GHG emissions from the emergency generator engines and the firewater pumps.

10.7.1. Step 1 - Identify All Available Control Technologies

The available GHG emission control strategies for emergency generators and firewater pumps that were analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration (CCS);
- Selection of fuel efficient engine;
- Fuel Selection; and
- Good Combustion Practices, Operating, and Maintenance Practices.

10.7.1.1. Carbon Capture and Sequestration

CCS is not considered an available control option for emergency equipment that operates on an intermittent basis and must be immediately available during plant emergencies without the constraint of starting up the CCS process.

10.7.1.2. Efficient Engine Design

Since EPEC is proposing to install a new firewater pump, the equipment is designed for optimal combustion efficiency.

10.7.1.3. Fuel Selection

The only technically feasible fuel for the firewater pump is diesel fuel. While natural gas-fueled firewater pumps may provide lower GHG emissions per unit of power output, natural gas is not considered a technically feasible fuel for the firewater pump since it will need to be used in the event of fire, when natural gas supplies may be interrupted.

10.7.1.4. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option for maintaining the combustion efficiency of the emergency equipment. Good combustion practices include proper maintenance and tune-up of the firewater pump at least annually per the manufacturer's specifications.

10.7.2. Step 2 - Eliminate Technically Infeasible Options

As discussed above, CCS is not technically feasible for the emergency equipment. Therefore, it has been eliminated from further consideration in the remaining steps of the analysis. As explained above, the only technically feasible fuel for the firewater pump is diesel fuel. All other control technologies are considered feasible.

10.7.3. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

EPEC will select a firewater pump with high fuel combustion efficiency and will implement good combustion, operating, and maintenance practices to minimize GHG emissions.

10.7.4. Step 4 - Evaluate Most Effective Control Options

No adverse energy, environmental, or economic impacts are associated with the above-mentioned technically feasible control options.

10.7.5. Step 5 - Select CO_2 BACT for Firewater Pump

Based on the selection of a fuel efficient firewater pump and implementing good combustion, operating and maintenance practices, EPEC proposes a CO_2e BACT limit of 8 tons per year on a 12-month rolling average basis for the firewater pump. To comply with the proposed CO_2e BACT limit, EPEC will purchase a firewater pump internal combustion engine (ICE) certified by the manufacturer to meet applicable emission standards and will also monitor diesel fuel usage on a monthly basis.

Actual CO_2e emissions from the fire pump will be calculated based on the fuel usage records and the emission factor for distillate fuel oil No. 2 combustion from Table C-1 to Subpart C of the MRR. Operation of the firewater pump, for purposes of maintenance checks and readiness testing (per recommendations from the government, manufacturer/vendor, or insurance), will be limited to 52 hours per year.

10.8. FUGITIVE COMPONENTS

The following sections present a BACT evaluation of fugitive CH_4 emissions. Piping components that produce fugitive emissions at the proposed project include: valves, pressure relief valves, pump seals, compressor seals, and sampling connections.

GHG emissions from leaking pipe components (fugitive emissions) from the proposed project include CH_4 and CO_2. The ratio of CO_2 to CH_4 in pipeline-quality natural gas is relatively low. For purposes of the GHG calculations, it was assumed all piping components are in a rich CH_4 stream.

10.8.1. Step 1 - Identify All Available Control Technologies

In determining whether a technology is available for controlling GHG emissions from fugitive components, permits and permit applications and EPA's RBLC were consulted. Based on these resources, the following available control technologies were identified:

- Installing leakless technology components to eliminate fugitive emission sources;
- Implementing various LDAR programs in accordance with applicable state and federal air regulations;
- Implementing an alternative monitoring program using a remote sensing technology such as infrared camera monitoring;
- Implementing an audio/visual/olfactory (AVO) monitoring program for compounds; and
- Designing and constructing facilities with high quality components and materials of construction compatible with the process.

10.8.2. Step 2 - Eliminate Technically Infeasible Options

Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used. These technologies are generally considered cost prohibitive except for specialized service. Some leakless technologies, such as bellows valves, if they fail, cannot be repaired without a unit shutdown that often generates additional emissions.

Recognizing that leakless technologies have not been universally adopted as LAER or BACT, even for toxic or extremely hazardous services, it is reasonable to state that these technologies are impractical for control of GHG emissions whose impacts have not been quantified. Any further consideration of available leakless technologies for GHG controls is unwarranted.

LDAR programs have traditionally been developed for the control of VOC emissions. BACT determinations related to control of VOC emissions rely on technical feasibility, economic reasonableness, reduction of potential environmental impacts, and regulatory requirements for these instrumented programs. Monitoring direct emissions of CO_2 is not feasible with the normally used instrumentation for fugitive emissions monitoring. However, instrumented monitoring is technically feasible for components in CH_4 service.

Alternate monitoring programs such as remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons.

Leaking fugitive components can be identified through audio, visual, or olfactory (AVO) methods. Natural gas leaks from components at the proposed facility are expected to have discernible odor to some extent, making them suitable for detection by olfactory means. A large leak can be detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are common and in place in industry.

A key element in the control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. For example, a valve that has been manufactured under high quality conditions can be expected to have lower runout on the valve stem, and the valve stem is typically polished to a smoother surface. Both of these factors greatly reduce the likelihood of leaking.

10.8.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Instrumented monitoring is effective for identifying leaking CH_4, but may be wholly ineffective for finding leaks of CO_2. With CH_4 having a global warming potential greater than CO_2, instrumented monitoring of the fuel and feed systems for CH_4 would be an effective method for control of GHG emissions. Quarterly instrumented monitoring with a leak definition of 500 ppmv, accompanied by intense directed maintenance, is generally assigned a control effectiveness of 97%.

Remote sensing using infrared imaging has proven effective for identification of leaks including CO_2. The process has been the subject of EPA rulemaking as an alternative monitoring method to the EPA's Method 21. Effectiveness is likely comparable to EPA Method 21 when cost is included in the consideration.

Audio/Visual/Olfactory means of identifying leaks owes its effectiveness to the frequency of observation opportunities. Those opportunities arise as operating technicians make rounds, inspecting equipment during those routine tours of the operating areas. This method cannot generally identify leaks at as low a leak rate as instrumented reading can identify; however, low leak rates have lower potential impacts than do larger leaks. This method, due to frequency of observation is effective for identification of larger leaks.

Use of high quality components is effective in preventing emissions of GHGs, relative to use of lower quality components.

10.8.4. Step 4 – Evaluate Most Effective Control Options

With leakless components eliminated from consideration, EPEC proposes to implement the most effective remaining control option. Instrumented monitoring implemented through the 28 MID LDAR program, with control effectiveness on 97%, is considered top BACT. An AVO program to monitor leaks also has a control effectiveness of 97% for most components. EPEC has chosen to implement an AVO program to monitor fugitive emissions from natural gas service piping components. The proposed project will also utilize high quality components and materials of construction, including gasketing, that are compatible with the service in which they are employed. Since EPEC is implementing the most effective control options available, additional analysis is not necessary.

10.8.5. Step 5 - Select CH_4 BACT for Fugitive Emissions

Fugitive CH_4 is the major component of the GHG emissions from piping components; EPEC proposes to implement a work practice as BACT. The AVO program will be used to detect any leaks and repairs will be performed as soon as practicable.

10.9. CIRCUIT BREAKERS

Sulfur hexafluoride (SF_6) gas is used in the circuit breakers associated with electricity generation equipment. Potential sources of SF_6 emissions include equipment leaks from SF_6 containing equipment, releases from gas cylinders used for equipment maintenance and repair operations, and SF_6 handling operations. The following section proposes appropriate GHG BACT for SF_6 emissions.

10.9.1. Step 1 - Identify All Available Control Technologies

In determining whether a technology is available for controlling and reducing SF_6 emissions from circuit breakers, permits and permit applications and EPA's RBLC were consulted. In addition, currently available literature was reviewed to identify emission reduction methods.[45,46,47] Based on these resources, the following available control technologies were identified:

- Use of new and state-of-the-art circuit breakers that are gas-tight and require less amount of SF_6;
- Evaluating alternate substances to SF_6 (e.g., oil or air blast circuit breakers);
- Implementing an LDAR program to identify and repair leaks and leaking equipment as quickly as possible;
- Systematic operations tracking, including cylinder management and SF_6 gas recycling cart use; and
- Educating and training employees with proper SF_6 handling methods and maintenance operations.

10.9.2. Step 2 - Eliminate Technically Infeasible Options

Of the control technologies identified above, only substitution of SF_6 with other non-GHG substance is determined as technically infeasible. While dielectric oil or compressed air circuit breakers have been used historically, these units require large equipment components to achieve the same insulating capabilities of SF_6 circuit breakers. In addition, per the EPA,

"No clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties."[48]

All other control technologies are technically feasible. EPEC proposes to implement these methods to reduce and control SF_6 emissions.

10.9.3. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Since EPEC proposes to implement feasible control options, ranking these control options is not necessary.

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[45] 10 Steps to Help Reduce SF_6 Emissions in T&D, Robert Mueller, Airgas Inc., available at: http://www.airgas.com/documents/pdf/50170-120.pdf.
[46] SF_6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report, U.S. Environmental Protection Agency, December 2008, available at: http://www.epa.gov/electricpower-sf6/documents/sf6_2007_ann_report.pdf.
[47] SF_6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source, J. Blackman (U.S. EPA, Program Manager, SF_6 Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting), June 2006, available at: http://www.epa.gov/electricpower-sf6/documents/leakrates_circuitbreakers.pdf.
[48] SF_6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report, U.S. Environmental Protection Agency, December 2008, available at: http://www.epa.gov/electricpower-sf6/documents/sf6_2007_ann_report.pdf.

10.9.4. Step 4 - Evaluate Most Effective Control Options

No adverse energy, environmental, or economic impacts are associated with the aforementioned technically feasible control options.

10.9.5. Step 5 - Select SF_6 BACT for Circuit Breakers

EPEC proposes the following work practices as SF_6 BACT:

- Use of state-of-the-art circuit breakers that are gas-tight and guaranteed to achieve a leak rate of 0.5% by year by weight or less (the current maximum leak rate standard established by the International Electrotechnical Commission [IEC]);
- Implementing an LDAR program to identify and repair leaks and leaking equipment as quickly as possible;
- Systematic operations tracking, including cylinder management and SF_6 gas recycling cart use; and
- Educating and training employees with proper SF_6 handling methods and maintenance operations.

11. PROFESSIONAL ENGINEER (P.E.) SEAL

The professional engineer (P.E.) seal is included in this section for the proposed project.

FORM PI-1 SECTION X PROFESSIONAL ENGINEER (P.E.) SEAL

I, ____________________, have reviewed the following sections of the attached application for an initial new source review permit submitted by EPEC:

Emissions Data

Best Available Control Technology

The capital cost of the project is estimated to be greater than $7,500,000.

The application for initial new source review, as referenced above, was reviewed on the 17th day of April 2012.

Signed: ____________________

Date: 4/17/2012

Professional Engineer Registration Number: 105305

STATE OF TEXAS
PAUL F. GREYWALL
105305
LICENSED
PROFESSIONAL ENGINEER

APPENDIX A

Alternatives Analysis Used to Define Project Scope

El Paso Electric Company (EPEC) provides the following explanation of its objectives in undertaking the Montana Station Project and of the alternatives considered to meet those objectives. This alternatives analysis is provided in support of public understanding of why EPEC has determined that simple cycle combustion turbines of roughly 100MW capacity each, installed over a period of roughly four years, is the sole means of generation available to meet EPEC's and its customers business needs.

EPEC is a public utility engaged in the generation, transmission and distribution of electricity in an area of approximately 10,000 square miles in the Rio Grande Valley in west Texas and south central New Mexico. EPEC owns or has significant ownership interests in five electrical generating facilities providing it with a total capacity of approximately 1,790 megawatts (MW). This total capacity is required to meet daytime summer peak for EPEC's 372,000 residential, commercial, industrial and wholesale customers. The end result of not meeting the summer peak would be rolling black outs.

Currently, EPEC owns and receives 741 MW of baseload capacity from the Palo Verde Nuclear Generating Station and the Four Corners Generating Station. These baseload stations are designed to deliver a set amount of electricity continuously, without interruption, throughout the year. Both of these resources are located outside the EPEC service area. During low load demands, this remote base load generation may be higher than the area's demand. In this scenario, the excess energy has to be sold to an out of area market. This means that EPEC's current and foreseeable baseload needs (the bottom of the diurnal and seasonal demand curves) are fully addressed.

To meet service needs above base load, EPEC generates approximately 1,053 MW of locally owned natural gas power generation equipment for intermediate and peak service. The local EPEC generation resources include 991 MW of "Intermediate Load" at Rio Grande Generating Station and Newman Generating Station. The local intermediate load facilities are not designed for rapid shutdown/startup, which is problematic during peak summer demand. EPEC does own a 62 MW peaking unit at Copper Generation Station which is used to supplement high peak loads typically associated with elevated summer temperatures as well as unscheduled outages of "Intermediate Load" generation.

A review of historic data indicates the region is experiencing an increase in load during peak times. This load growth has many contributing factors, including the rapidly growing population density on the El Paso's eastside, and additional troops being deployed to Fort Bliss for the expansion project. Both of these areas will be served by the proposed Montana Power Station. Also, the majority of the residential households are cooled in summer months by evaporative coolers or with refrigerant air conditioners. As a result to the local utilities rebate program, a steady increase in the replacement of electric efficient water evaporative cooler to the less electric efficient refrigerant air conditioners has resulted in a continuous increase in summer peak electric demand in EPEC's service area. EPEC has determined there is a requirement to construct new generation units to maintain reliability and meet the summer peak load while keeping customer cost down.

Based on EPEC's 2011 Long-term and Budget Year Forecast, additional generation resources are needed in 2014, 2015, and 2016 to meet peak load. EPEC's forecast shows that incremental resource additions will meet the yearly forecasted peak load requirement while maintaining the required 15% reserve margin. Resource additions must offer a quick start capability, no more than a 10 minute start, in order to serve as capacity towards EPEC's required reserve margin. In addition, EPEC operates in the Western Electricity Coordinating Council (WECC). Per WECC, EPEC must maintain a certain level of operating reserves on-line in case of transmission or generating unit outages. These reserves can be in the form of spinning reserves (units which are on-line but not fully loaded) or quick start units. To qualify for quick start designation, the unit must be on-line in less than 10 minutes. Otherwise, the unit does not count towards quick start designation for meeting operating reserves.

EPEC's Resource Planning Department conducted a study to determine which type of generation would be best to meet its increasing peaking summer load. The goal of the study was to evaluate power generation that met the following requirements:

- 80-100 MW in 2014
- 80-100 MW in 2015

- 160-200 MW in 2016
- Dispatchable on hourly/daily basis (<10 minutes)
- Automatic Generation Control (AGC)
- Reliable under extreme high or low temperatures (-10° F to 105° F)
- Minimum 20 year contract

As stated above, EPEC has an adequate amount of baseload capacity; therefore more base load generation such as coal and nuclear would not address the need for additional peaking power during the summer months. Due to inconsistent weather patterns, wind generated resources within EPEC's service territory produce large variability on the electric delivery system. This unreliable delivery of electricity will require an additional generating source to back it up. Weather patterns in EPEC's service region allow for wind generation during off peak hours which is not a topic of concern due to the greatly reduced load during off peak and the large amount of baseload capacity. Battery Storage is a new technology that is being introduced into the electric utility market. Due to the high cost of this new technology and the lack of proven long term reliability, this option is deemed too high of a risk. Load curtailment capacities are limited in EPEC's service area and additional resources would still be required to meet the peak load. In 2012, EPEC will have a total of 47 MW of solar generation on its system. Solar energy, much like wind, is variable and requires quick ramping generation to back it up. Additional solar energy could be possible in the future once the effect on EPEC system is studied further. Gas fired generation is the only practical solution to meet the increasing summer peak load due to the capability of starting and ramping up and cycling off at night when the load drops considerably.

EPEC conducted a study to determine the best gas fired generating units to meet the object of the project. The study included the use of the commercially available software, PROMOD, which determines the least cost option and the best technical options for the new power generation units. PROMOD is a software program that simulates the economic dispatch of an electrical grid system. This software takes into account EPEC's existing generation units as well as the additional resources required to meet EPEC's load demands. PROMOD was specifically used to analyze alternative generation expansion plans as in this case. The inputs required in PROMOD include fuel and purchased power data, generating unit characteristics, heat rates, load data, and general system data. Various scenarios of PROMOD were modeled with differences in minimum loads, cycling capabilities, and heat rates.

While reviewing the results of this study, please keep in mind that EPEC is a summer peaking utility. A summer peaking utility means the EPEC power generation will experience a significantly higher load during the day from May to August than other times of the year. In addition, off–peak hour loads decrease significantly due to the mild weather in the El Paso area. System load demand can be significantly lower in the off-peak hours, especially in the winter months, than those seen during the peak summer hours. To efficiently meet the load demand, EPEC's generation must be readily available during daytime summer conditions and able to cycle or shut down completely during off-peak periods (e.g. nights, weekends, and winter). For an illustration of how the load peaks during a summer day please refer to Figure 1 below.

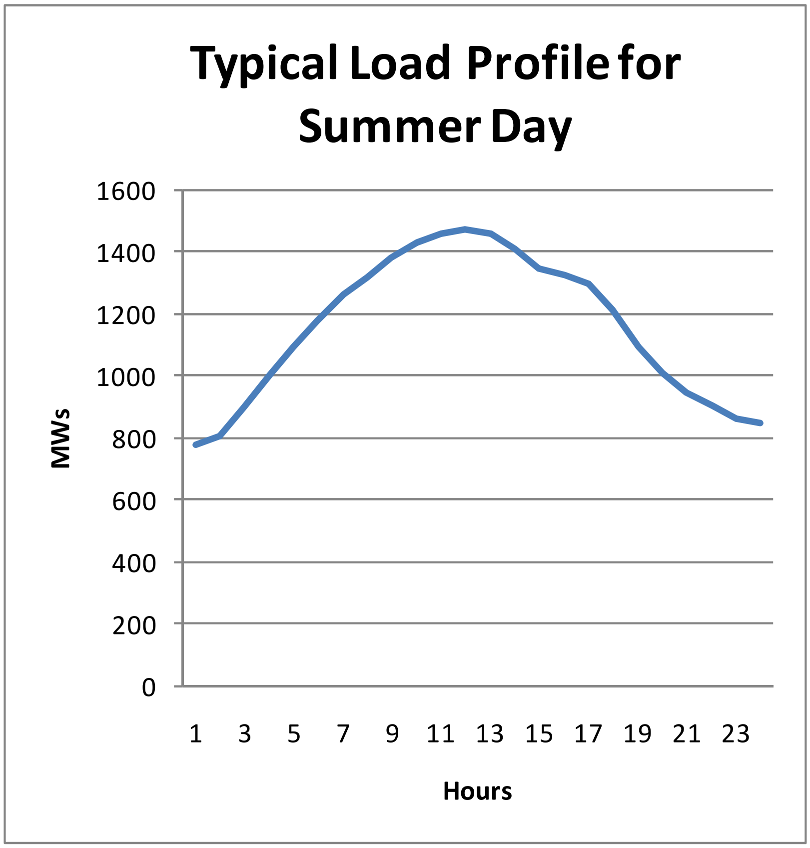

Figure 1 – EPEC's Daily Load Profile

Figure 1 indicates there is a minimum of approximately 800 MW used continuously. The 800 MW is base load, which is met frequently by the base load generation produced at Palo Verde and Four Corners. Once the load demand increases, the local intermediate load units began to increase their output from a lower nighttime level to a maximum daytime level to meet the load demand. However, during the high peak hours from about 11:00 am to 6:00 pm the baseload and intermediate load generation combined cannot satisfy the peak load demand; additional peak generation is required. The continuously increasing summer daytime peak load has rendered Copper Generating Station insufficient to meet the additional demand.

To meet this peak load EPEC has two choices to consider when designing new generation units. The first choice is a Simple Cycle Combustion Turbine (SCCT). EPEC modeled the LMS100 SCCT produced by General Electric. This turbine utilizes technology that is similar to the type of engine you would find on an airplane. Currently, the LMS100 is the largest and most efficient combustion turbine in its class and is capable of producing 89.9 MW. The LMS100 offers a wide range of flexibility when it comes to unit operation. This turbine can be used as a peaker, for intermediate load, and even for base load. The LMS100 offers quick starts, less than 10 minutes, which create excellent cycling capability, while keeping emissions low, and based on PROMOD an average Heat Rate of approximately 9,200 BTU/kWh can be experienced when used in EPEC's system. The unit has excellent cycling capability, in which the unit can be shut down and restarted faster than a combined unit. Due to improvements in technology as compared to older simple cycle units, the LMS100 could be dispatched ahead of many of our units which have a higher heat rate. The LMS100 is one of the most efficient peaking units on the market, comparatively; the LMS100 reportedly exhibits a heat rate that is lower than our older Combined Cycle Combustion Turbine (CCCT) units.

The second choice was a CCCT, which is a combination of combustion and steam turbine technologies. The CCCT modeled in PROMOD analysis is a 2x1 unit, which utilizes two combustion turbines and one steam turbine. The CCCTs may be very efficient if operated in intermediate to baseload mode, because they can then utilize waste heat recovery recovered from the combustion turbine exhaust to power the steam turbine. The CCCT modeled in PROMOD is based on the operation characteristics of EPEC's current most efficient unit, Newman 5. This unit can produce 288 MW with duct firing and provide a Heat Rate of about 8,500 BTU/kWh when dispatched based on EPEC's system need, per PROMOD. This heat rate is achieved when the unit is run as an intermediate/base load unit with duct firing. Using the unit in this fashion means it may not be shut down during off peak hours and there will be constant generation. Cycling is limited with a CCCT since these units are larger and have thermal penalities, they operate with a boiler making them often used for intermediate and base load applications. This is a disadvantage of the CCCT compared to the SCCT.

New fast-start CCCT (30 min start) industrial turbines are currently available in much larger increments than the 100 MW as defined for the project. A larger capacity turbine would be operated at less than optimum (full load) output more frequently than a smaller capacity turbine, since gas turbine efficiency drops rapidly at less than full load, this mode of operation would reduce the overall efficiency and incur thermal penalties for starts of the CCCT unit to that below an efficient SCCT.

Results obtained from performing several case studies in PROMOD, indicated that even though the SCCT has a higher heat rate, which means it burns more fuel in the short term, the SCCT actually saves fuel over the CCCT because it can be shut down during off peak hours. This saving in fuel reduces overall cost to the customer while reducing emissions which are created during generation of excess electricity. Through the PROMOD case studies, the SCCTs exhibited a dual purpose advantage to our system. Not only was it utilized to meet the peak load during the summer, the SCCT was dispatched ahead of many of our less efficient and older units.

Since EPEC has a considerable amount of base load resources dominated by nuclear and coal resources, the remaining units must be able to cycle on and off on a daily basis. This is not possible for many of EPEC's local generation units due to their age and technology. EPEC's system needs the flexibility to shut down the generating units during off peak hours or at night. This critical characteristic will allow the units to easily conform to EPEC's daily load profile. New generation units must be able to start and ramp up quickly to meet the daytime summer loads and cycle off at night when the load drops considerably. EPEC also needs to be able to add the capacity in stages (roughly 100MW/year) to match the expected growth in demand over that period of time. Because only simple cycle turbines satisfy these two fundamental needs, EPEC is proposing to construct four SCCT generating units, each with a power generation output capacity of approximately 89.9 MW.

APPENDIX B

GHG Emission Calculations

SITE-WIDE GHG EMISSIONS SUMMARY

Annual Potential GHG Emission Rates

EPN	Emission Point Description	GHG Emission Rates (metric tons per year) CO_2	CH_4	N_2O	SF_6	Total CO_2e [2]	Percent Contribution [1] (%)
FWP-1	Fire Water Pump	7.85	0.00	0.00	-	7.88	0.00
GT-1	Combustion Turbine 1	227,601.61	5.00	0.43	-	227,839.65	24.99
GT-2	Combustion Turbine 2	227,601.61	5.00	0.43	-	227,839.65	24.99
GT-3	Combustion Turbine 3	227,601.61	5.00	0.43	-	227,839.65	24.99
GT-4	Combustion Turbine 4	227,601.61	5.00	0.43	-	227,839.65	24.99
CTBR-SF6	Fugitive SF_6 Circuit Breaker Emissions	-	-	-	0.014	334.98	0.04
FUG-1	Components Fugitive Leak Emissions	-	0.13	-	-	2.81	0.00
	Total	**910,414.27**	**20.13**	**1.72**	**1.40E-02**	**911,704.26**	**100.00**

[1] Percent Contribution (%) = Total CO_2e for each EPN (tpy) / Total CO_2e (tpy) * 100

[2] Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials.

GHG EMISSION CALCULATIONS FOR COMBUSTION TURBINES

Combustion Sources of GHG Emissions

Parameter	Units	Fire Water Pump	Combustion Turbine 1	Combustion Turbine 2	Combustion Turbine 3	Combustion Turbine 4
EPN	-	FWP-1	GT-1	GT-2	GT-3	GT-4
Rated Capacity [1]	MMBtu/hr	2.03	858.55	858.55	858.55	858.55
Hours of Operation per Year[5]	hrs/yr	52	5,000	5,000	5,000	5,000
Natural Gas Potential Throughput [2]	scf/yr	--	4,233,481,262	4,233,481,262	4,233,481,262	4,233,481,262
Diesel Potential Throughput [4]	gal/yr	770	--	--	--	--
Natural Gas High Heat Value (HHV) [3]	MMBtu/scf	--	1.014E-03	1.014E-03	1.014E-03	1.014E-03
No.2 Fuel Oil High Heat Value (HHV) [3]	MMBtu/gal	0.138	--	--	--	--

[1] Estimated Maximum Heat Input (MMBtu/hr) = Fuel Heat Value (Btu/gal) x Fuel Usage (gal/hr) x (1 MMBtu/1,000,000 Btu)

Estimated Maximum Heat Input = 138,000 (Btu/gal) x 14.8 (gal/hr) x (1 MMBtu/ 1,000,000 Btu) = 2.03 MMBtu/ hr

[2] Natural gas throughput is based on heat capacity of the unit, hours of operation and the fuel's high heating value

[3] High heating value for No.2 Fuel Oil obtained from 40 CFR Part 98, Subpart C, Table C-1. 2 Natural gas heating values obtained from the natural gas analysis provided by Mr. Robert Daniels (El Paso Electric Company) to Ms. Christine Chambers (Trinity Consultants) via email on February 27, 2012.

[4] Diesel throughput is based on From Page 5 of the Spec sheet, located under References/Fire Pump Engine Spec Sheet folder ("John Deere JW6H.pdf"). 14.8 gal/hr

[5] Annual hours of operation information provided by Mr. Robert Daniels (El Paso Electric Company) to Ms. Latha Kambham (Trinity Consultants) via email on March 26, 2012. This includes hours for MSS activities.

GHG Emission Factors for Diesel Engine

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	73.960	kg CO_2/MMBtu
CH_4 [2]	0.003	kg CH_4/MMBtu
N_2O [2]	0.0006	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Distillate Fuel Oil No. 2.

[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for petroleum fuel.

GHG Emission Factors for Natural Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Natural Gas.

[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for Natural Gas.

Turbine Capacities

Parameter[1]	Value
Rated KW	99991
MMBtu/Hr (HHV)	858.55

[1] Data obtained from the GE Performance Data provided by Mr. Rober Daniels (EPEC) via email on April, 10, 2012. Data represents the maximum values.

GHG Potential Emission Calculations

EPN	Description	Fuel Type	Tier Used	Annual Emissions [1, 2] (metric tons/yr) CO_2	CH_4	N_2O	CO_2e [4]	Hourly Emissions [3] (lb/hr) CO_2	CH_4	N_2O	CO_2e [4]
FWP-1	Fire Water Pump	No.2 Fuel Oil	Tier I	8	3.19E-04	6.37E-05	8	333	0.01	0.00	334
GT-1	Combustion Turbine 1	Natural Gas	Tier I	227,602	4.29	0.43	227825	100,355	1.89	0.19	100454
GT-2	Combustion Turbine 2	Natural Gas	Tier I	227,602	4.29	0.43	227825	100,355	1.89	0.19	100454
GT-3	Combustion Turbine 3	Natural Gas	Tier I	227,602	4.29	0.43	227825	100,355	1.89	0.19	100454
GT-4	Combustion Turbine 4	Natural Gas	Tier I	227,602	4.29	0.43	227825	100,355	1.89	0.19	100454
			Total	910,414.27	17.17	1.72	911,307	401,753.61	7.58	0.76	402,148
			Total CO_2e Emissions [4]	-	-	-	911,307	-	-	-	402,148

[1] CO_2 emissions from No.2 Fuel Oil and Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.

[2] CH_4 and N_2O emissions No.2 Fuel Oil and Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.

[3] metric tons to lb conversion 2204.623 lb/metric tons

[4] Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

GHG EMISSIONS FROM COMBUSTION TURBINE STARTUP ACTIVITIES

Unburned Methane Emissions During Startup **(Conservatively assuming 100% Methane content of Natural Gas)**

	Per Turbine	Project Total
Maximum Annual Turbine Startups	832	3328
CH_4 Emissions		
UHC emissions per startup event (lbs/startup event)[1]	0.8	
Annual CH_4 Emissions [2] (metric tons/yr)	0.30	1.21
CO_2e Emissions		
Annual CO_2e Emissions [3] (metric tons/yr)	6.34	25.36

1 The CH_4 startup emissions are conservatively assumed to be the UHC emission provided by GE

[2] Annual emissions (tpy) = Maximum Annual Turbine Starts (startup events/yr) * Event (lb/startup event) / (2204.623 lb/metric ton)

$$\text{Annual } CH_4 \text{ Emissions (tpy)} = \frac{832 \text{ events}}{\text{yr}} \times \frac{0.80 \text{ lb}}{\text{event}} \times \frac{1 \text{ metric ton}}{2204.623 \text{ lb}} = 0.30 \text{ tpy}$$

[3] Global Warming Potential of CH_4 = 21 per 40 CFR 98, Subpart A, Table A-1

GHG EMISSIONS FROM COMBUSTION TURBINE SHUTDOWN ACTIVITIES

Unburned Methane Emissions During Shutdown **(Conservatively assuming 100% Methane content of Natural Gas)**

	Per Turbine	Project Total
Maximum Annual Turbine Shutdown	832	3328
CH_4 Emissions		
UHC emissions per shutdown event (lbs/shutdown event)[1]	1.07	
Annual CH_4 Emissions[2] (metric tons/yr)	0.40	1.62
CO_2e Emissions		
Annual CO_2e Emissions[3] (metric tons/yr)	**8.48**	**33.92**

1 The CH_4 startup emissions are conservatively assumed to be the UHC emission provided by GE

2 Annual emissions (tpy) = Maximum Annual Turbine Shutdowns (shutdown events/yr) * Event (lb/shutdown event) / (2204.623 lb/metric ton)

$$\text{Annual } CH_4 \text{ Emissions (tpy)} = \frac{832 \text{ events}}{\text{yr}} \left| \frac{1.07 \text{ lb}}{\text{event}} \right| \frac{1 \text{ metric ton}}{2204.623 \text{ lb}} = 0.40 \text{ tpy}$$

3 Global Warming Potential of CH_4 = 21 per 40 CFR 98, Subpart A, Table A-1

GHG EMISSION CALCULATIONS FOR SF_6 CIRCUIT BREAKERS

Circuit Breaker SF_6 Emission Rates

EPN	Description	Circuit Breaker Rating [1]	Amount of SF_6 in Full Charge [1] (lb)	SF_6 Leak Rate [2] (%/yr)	Annual SF_6 Emission Rate [3] (metric tons /yr)	Annual CO_2e Emission Rate [4] (metric tons/yr)
CTBR-SF_6	Circuit Breaker 1 Equipment Leak	10,000 Amps @ 25.3 kKv	35	0.50	7.94E-05	1.90
	Circuit Breaker 2 Equipment Leak	10,000 Amps @ 25.3 kKv	35	0.50	7.94E-05	1.90
	Circuit Breaker 3 Equipment Leak	10,000 Amps @ 25.3 kKv	35	0.50	7.94E-05	1.90
	Circuit Breaker 4 Equipment Leak	10,000 Amps @ 25.3 kKv	35	0.50	7.94E-05	1.90
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	145PM63-20	115	64	0.50	1.45E-04	3.47
	LPO-362	345	140	0.50	3.18E-04	7.59
	362PMI 40-20	345	300	0.50	6.80E-04	16.26
	362PMI 40-20	345	300	0.50	6.80E-04	16.26
	362GA40-20C	345	1850	0.50	4.20E-03	100.28
	362GA40-20C	345	1850	0.50	4.20E-03	100.28
Total					**1.40E-02**	**334.98**

[1] Information on Circuit Breakers provided by EPEC (Mr. Robert Daniels) to Trinity (Ms. Christine Chambers) via email dated 3/7/2012. The Circuit Breakers are ABB Model HECS100M units.

[2] From EPA's technical paper titled, "SF6 Leak Rates from High Voltage Circuit Breakers - U.S. EPA Investigates Potential Greenhouse Gas Emission Source - by J. Blackman, Program Manager, U.S. EPA and M. Averyt, ICF Consulting, and Z. Taylor, ICF Consulting". Used the worst-case estimate of 0.5% per year.

[3] Annual Emission Rate (tpy) = Number of Vessels Per Breaker * Amount of SF_6 in Full Charge (lb) * SF_6 Leak Rate (%/yr) * 1/2204.623 (metric ton/lb)

[4] Global Warming Potential (GWP) of SF_6 = 23,900

GHG EMISSION CALCULATIONS FOR FUGITIVE EMISSIONS FROM EQUIPMENT LEAKS

Fugitive GHG Emissions Rates

EPN	Components	Component Count [1]	Emission Factors [2] (lb/hr-component)	Control Efficiency [7] (%)	CH_4 Emissions [3, 4, 5] (metric tons/yr)	Annual CO_2e Emissions [6] (metric tons/yr)
FUG-1	Valves	106	0.00992	97%	0.12	2.62
	Pressure Relief Valves	0	0.0194	97%	0.00E+00	0.00
	Flanges	86	0.000860	97%	8.86E-03	0.19
	Pumps	0	0.0194	93%	0.00E+00	0.00
	Open-ended Lines	0	0.00441	97%	0.00E+00	0.00
	Connectors	0	0.000440	97%	0.00E+00	0.00
				Total Emissions	**0.13**	**2.81**

[1] Component counts based on a sister facility owned and operated by El Paso Electric. A 20% safety factor is also included in the fugitive component counts.

[2] Emission factors obtained from Table 2 for Oil and Gas Production Operations from Addendum to RG-360, *Emission Factors for Equipment Leak Fugitive Components,* TCEQ, January 2005, Gas factors.

[3] The methane content in the gas is conservatively assumed to be 100 %.

[4] The annual hours of operation are 8,760 hrs/yr.

[5] Annual Emission Rate (tpy) = Component Count * Emission Factor (lb/hr-component) * Methane Content (%) * Annual Hours of Operation (hrs/yr) * 1/2204.623 (metric ton/lb)

CH_4 Annual Emissions from Valves (tpy) = $\frac{105.6 \text{ components}}{} \times \frac{0.00992 \text{ lb}}{\text{hr - component}} \times \frac{100\ \%}{100} \times \frac{8{,}760 \text{ hrs}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}}$ = 0.12 tpy

[6] Global Warming Potential of CH_4 = 21 per 40 CFR 98, Subpart A, Table A-1

[7] The Montana Power Station will implement Audio/Visual/Olfactory (AVO) program to minimize emissions. Control efficiencies are obtained from October 2000 Draft TCEQ Technical Guidance Package.

APPENDIX C

GE LMS100 Combustion Turbine Literature

GE Energy

New High Efficiency Simple Cycle Gas Turbine – GE's LMS100™

imagination at work

Authored by:
Michael J. Reale
LMS100™ Platform Manager

GER-4222A (06/04)

New High Efficiency Simple Cycle Gas Turbine – GE's LMS100™

Contents:

New High Efficiency Simple Cycle Gas Turbine – GE's LMS100™

Abstract

GE has introduced the first modern production gas turbine in the power generation industry to employ off-engine intercooling technology with the use of an external heat exchanger, the LMS100™. This gas turbine provides the highest simple cycle efficiency in the Industry today and comes on the heels of GE's introduction of the highest combined cycle gas turbine system, the MS9001H. The LMS100™ system combines frame and aeroderivative gas turbine technology for gas fired power generation. This marriage provides customers with cyclic capability without maintenance impact, high simple cycle efficiency, fast starts, high availability and reliability, at low installed cost. The unique feature of this system is the use of intercooling within the compression section of the gas turbine, leveraging technology that has been used extensively in the gas and air compressor industry. Application of this technology to gas turbines has been evaluated by GE and others extensively over many years although it has never been commercialized for large power generation applications. In the past five years, GE has successfully used the SPRINT® patented spray intercooling, evaporative cooling technology between the low and high pressure compressors of the LM6000™ gas turbine, the most popular aeroderivative gas turbine in the 40 to 50MW range. GE's development of high pressure ratio aircraft gas turbines, like the GE90®, has provided the needed technology to take intercooling to production. The LMS100™ gas turbine intercooling technology provides outputs above 100MW, reaching simple cycle thermal efficiencies in excess of 46%. This represents a 10% increase over GE's most efficient simple cycle gas turbine available today, the LM6000™.

Introduction

GE chose the intercooled cycle to meet customers' need for high simple cycle efficiency. The approach to developing an intercooled gas turbine is the result of years of intercooled cycle evaluation along with knowledge developed with operation of SPRINT® technology. Matching current technology with customer requirements results in a system approach to achieving a significant improvement in simple cycle efficiency.

The development program requirement was to use existing and proven technology from both GE Transportation (formerly GE Aircraft Engines) and GE Energy (formerly GE Power Systems), and combine them into a system that provides superior simple cycle performance at competitive installed cost. All component designs and materials, including the intercooler system, have been successfully operated in similar or more severe applications. The combination of these components and systems for a production gas turbine is new in the power generation industry.

The GE Transportation CF6-80C2/80E gas turbine provided the best platform from which to develop this new product. With over 100 million hours of operating experience in both aircraft engines and industrial applications, through the LM6000™ gas turbine, the CF6® gas turbine fits the targeted size class. The intercooling process allowed for a significant increase in mass flow compared to the current LM™ product capability. Therefore, GE Energy frame units were investigated for potential Low Pressure Compressors (LPC) due to their higher mass flow designs. The MS6001FA (6FA) gas turbine compressor operates at 460 lbm/sec (209 kg/sec) and provides the best match with the CF6-80C2 High Pressure Compressor (HPC) to meet the cycle needs.

New High Efficiency Simple Cycle Gas Turbine – GE's LMS100™

The LMS100™ system includes a 3-spool gas turbine that uses an intercooler between the LPC and the HPC as shown in Fig. 1.

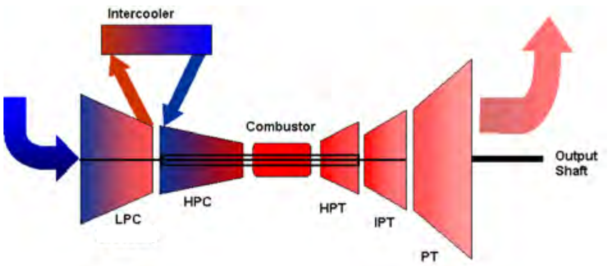

Fig. 1. LMS100™ GT Configuration

Intercooling provides significant benefits to the Brayton cycle by reducing the work of compression for the HPC, which allows for higher pressure ratios, thus increasing overall efficiency. The cycle pressure ratio is 42:1. The reduced inlet temperature for the HPC allows increased mass flow resulting in higher specific power. The lower resultant compressor discharge temperature provides colder cooling air to the turbines, which in turn allows increased firing temperatures at metal temperatures equivalent to the LM6000™ gas turbine producing increased efficiency. The LMS100™ system is a 2550°F (1380°C) firing temperature class design.

This product is particularly attractive for the peaking and mid-range dispatch applications where cyclic operation is required and efficiency becomes more important with increasing dispatch. With an aeroderivative core the LMS100™ system will operate in cyclic duty without maintenance impact. The extraordinary efficiency also provides unique capability for cogeneration applications due to the very high power-to-thermal energy ratio. Simple cycle baseload applications will benefit from the high efficiency, high availability, maintainability and low first cost.

GE, together with its program participants Avio, S.p.A., Volvo Aero Corporation and Sumitomo Corporation, are creating a product that changes the game in power generation.

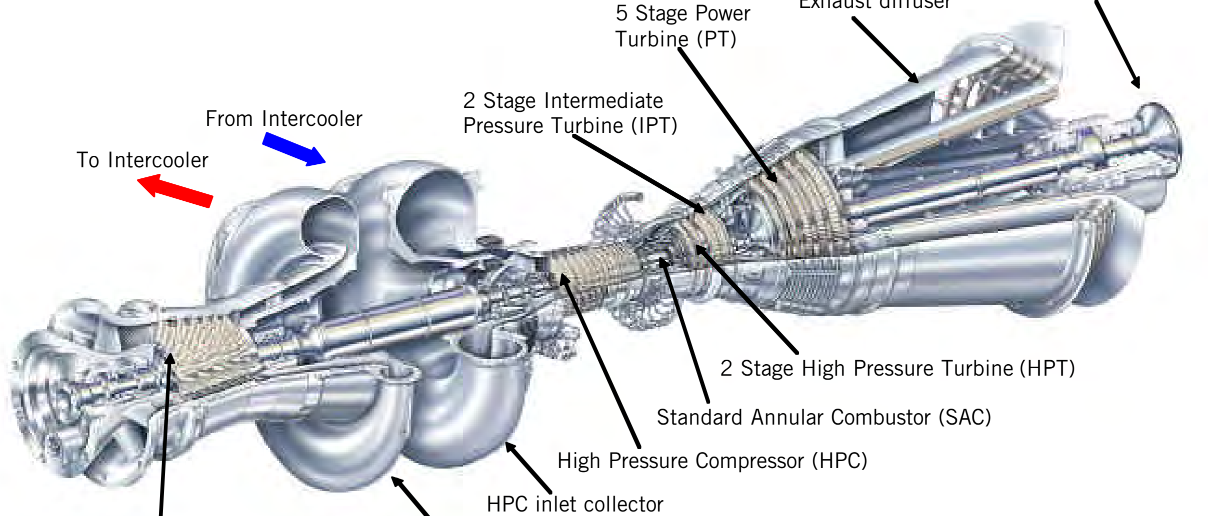

Fig. 2. LMS100™ Gas Turbine

Gas Turbine Design

The LMS100™ system combines the GE Energy FA compressor technology with GE Transportation CF6®/LM6000™ technology providing the best of both worlds to power generation customers. Fig. 2 shows the gas turbine architecture.

The LPC, which comprises the first 6 stages of the 6FA, pumps 460 lb/sec (209 kg/sec) of airflow (1.7 X the LM6000™ airflow). This flow rate matched the capability of the core engine in the intercooled cycle, making it an ideal choice. The LMS100™ system LPC operates at the same design speed as the 6FA, thereby reducing development requirements and risk. The compressor discharges through an exit guide vane and diffuser into an aerodynamically designed scroll case. The scroll case is designed to minimize pressure losses and has been validated through 1/6 scale model testing. Air leaving the scroll case is delivered to the intercooler through stainless steel piping.

Air exiting the intercooler is directed to the HPC inlet scroll case. Like the LPC exit scroll case, the HPC inlet collector scroll case is aerodynamically designed for low pressure loss. This scroll case is mechanically isolated from the HPC by an expansion bellows to eliminate loading on the case from thermal growth of the core engine.

The HPC discharges into the combustor at ~250°F (140°C) lower than the LM6000™ aeroderivative gas turbine. The combination of lower inlet temperature and less work per unit of mass flow results in a higher pressure ratio and lower discharge temperature, providing significant margin for existing material limits. The HPC airfoils and casing have been strengthened for this high pressure condition.

The combustor system will be available in two configurations: the Single Annular Combustor (SAC) is an aircraft style single dome system with water or steam injection for NOx control to 25 ppm; and the Dry Low Emissions-2 (DLE2) configuration, which is a multi-dome lean premixed design, operating dry to 25 ppm NOx and CO. The DLE2 is a new design based on the proven LM™ DLE combustor technology and the latest GE Transportation low emissions technology derived from the GE90® and CFM56® gas turbines. GE Global Research Center (GRC) is supporting the development program by providing technical expertise and conducting rig testing for the DLE2 combustor system.

The HPT module contains the latest airfoil, rotor, cooling design and materials from the CF6-80C2 and -80E aircraft engines. This design provides increased cooling flow to the critical areas of the HPT, which, in conjunction with the lower cooling flow temperatures, provides increased firing temperature capability.

The IPT drives the LPC through a mid-shaft and flexible coupling. The mid-shaft is the same design as the CF6-80C2/LM6000™. The flexible coupling is the same design used on the LM2500™ marine gas turbine on the U.S. Navy DDG-51 Destroyers. The IPT rotor and stator components are being designed, manufactured and assembled by Avio, S.p.A. as a program participant in the development of the LMS100™ system. Volvo Aero Corporation as a program participant manufactures the Intermediate Turbine Mid-Frame (TMF) and also assembles the liners, bearings and seals.

The IPT rotor/stator assembly and mid-shaft are assembled to the core engine to create the 'Supercore.' This Supercore assembly can be replaced in the field within a 24-hour period.

Lease pool Supercores will be available allowing continued operation during overhaul periods or unscheduled events.

The Power Turbine (PT) is a 5-stage design based on the LM6000™ and CF6-80C2 designs. Avio, S.p.A. is designing the PT for GE Transportation and manufacturing many of the components. Volvo Aero Corporation is designing and manufacturing the PT case. The Turbine Rear Frame (TRF) that supports the PT rotor/stator assembly and the Power Turbine Shaft Assembly (PTSA) is based on GE Energy's frame technology. The PTSA consists of a rotor and hydrodynamic tilt-pad bearings, including a thrust bearing. This system was designed by GE Energy based on extensive frame gas turbine experience. The PT rotor/stator assembly is connected to the PTSA forming a free PT (aerodynamically coupled to the Supercore), which is connected to the generator via a flexible coupling.

The diffuser and exhaust collector combination was a collaborative design effort with the aero design provided by GE Transportation and the mechanical design provided by GE Energy. GE Transportation's experience with marine modules and GE Energy's experience with E and F technology diffuser/collector designs were incorporated.

Intercooler System Design

The intercooler system consists of a heat exchanger, piping, bellows expansion joints, moisture separator and variable bleed valve (VBV) system. All process air wetted components are made of stainless steel. The LMS100™ system will be offered with two types of intercooling systems, a wet system that uses an evaporative cooling tower and a dry system (no water required).

The wet system uses an air-to-water heat exchanger of the tube and shell design, as shown in Fig. 3.

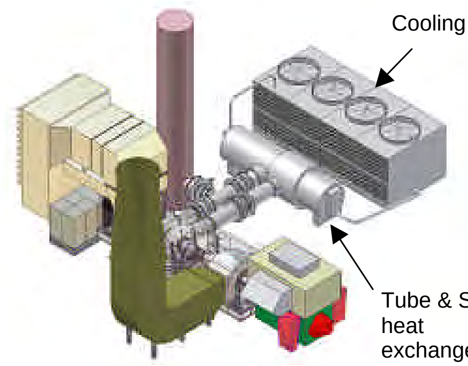

Fig. 3. LMS100™ Wet Intercooler System

The tube and shell heat exchanger is used extensively throughout the compressed air and oil & gas industries, among others. The design conditions are well within industry standards of similar-sized heat exchangers with significant industrial operating experience. This design is in general conformance with API 660 and TEMA C requirements.

The intercooler lies horizontal on supports at grade level, making maintenance very easy. Applications that have rivers, lakes or the ocean nearby can take advantage of the available cooling water. This design provides plant layout flexibility. In multi-unit sites a series of evaporative cooling towers can be constructed together, away from the GT, if desirable, to optimize the plant design.

An optional configuration using closed loop secondary cooling to a finned tube heat exchanger (replacing the evaporative cooling towers) will also be available (See Fig. 4). This design uses the same primary heat exchanger (tube and shell), piping, bellows expansion joints and VBV system, providing commonality across product configurations. The secondary cooling system can be water or glycol. This system is beneficial in cold and temperate climates or where water is scarce or expensive.

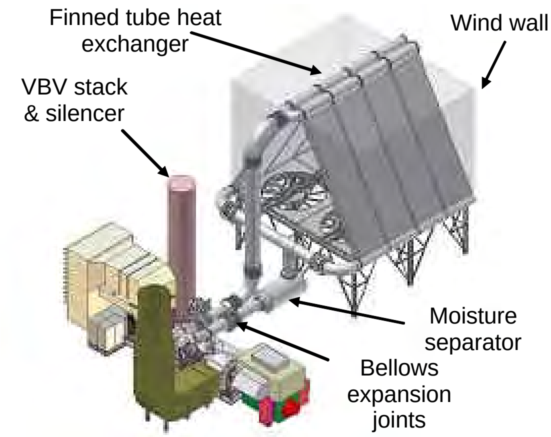

Fig. 4. LMS100™ Dry Intercooler System with Air-to-Air Heat Exchanger

An alternate dry intercooler system is being developed for future applications, and uses an air-to-air heat exchanger constructed with panels of finned tubes connected to a header manifold. This design is the same as that used with typical air-cooled systems in the industry. The main difference is mounting these panels in an A-frame configuration. This configuration is typically used with steam condensers and provides space advantages together with improved condensate drainage. The material selection, design and construction of this system are in general conformance with American Petroleum Institute (API) Standard 661 and are proven through millions of hours of operation in similar conditions.

The air-to-air system has advantages in cold weather operation since it does not require water and therefore winterization. Maintenance requirements are very low since this system has very few moving parts. In fact, below 40°F (4°C) the fans are not required, thereby eliminating the parasitic loss. In high ambient climates the performance of the air-to-air system can be enhanced with an evaporative cooling system integrated with the heat exchanger. This provides equivalent performance to the air-to-water system. Water usage will be low and intermittent since it would only be used during the peak temperature periods, resulting in a very low yearly consumption.

Package Design

The gas turbine is assembled inside a structural enclosure, which provides protection from the environment while also reducing noise (see Fig. 5). Many customer-sensing sessions were held to determine the package design requirements, which resulted in a design that has easy access for maintenance, quick replacement of the Supercore, high reliability and low installation time. Package design lessons learned from the highly successful LM6000™ gas turbine and GE's experiences with the 9H installation at Baglan Bay have been incorporated into the LMS100™ system package design. The complete GT driver package can be shipped by truck. This design significantly reduces installation time and increases reliability.

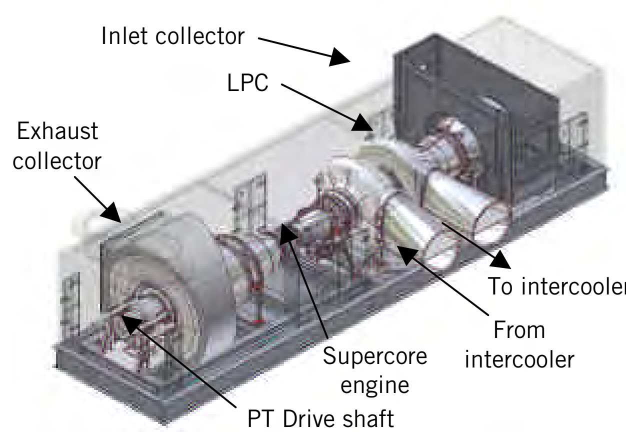

Fig. 5. LMS100™ System GT Driver Package

The auxiliary systems are mounted on a single skid in front of the GT driver package. This skid is pre-assembled and factory tested prior to shipment. The auxiliary skid connects with the base plate through short, flexible connectors. This design improves reliability and reduces interconnects and site installation cost (see Fig. 6).

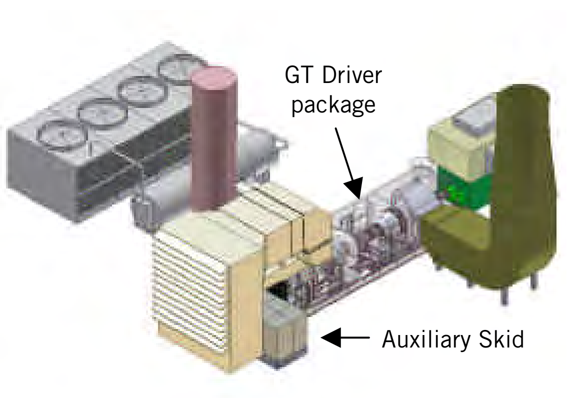

Fig. 6. LMS100™ System Auxiliary Skid Location

The control system design is a collaboration of GE Transportation and GE Energy. It employs triple processors that can be replaced on-line with redundant instrumentations and sensors. The use of GE Transportation's synthetic modeling will provide a third level of redundancy based on the successful Full Authority Digital Electronic Control (FADEC) design used in flight engines. The control system is GE Energy's new Mark VI, which will be first deployed on the LM6000™ gas turbine in late 2004 (ahead of the LMS100™ system).

The inlet system is the MS6001FA design with minor modifications to adjust for the elimination of the front-mounted generator and ventilation requirements.

The exhaust systems and intercooler systems are designed for right- or left-handed installation.

Reliability and Maintainability

The LMS100™ system is designed for high reliability and leverages LM™ and GE Energy frame technology and experience, along with GE Transportation technology. The use of Six Sigma processes and methods, and Failure Modes and Effects Analysis (FMEA) for all systems identified areas requiring redundancy or technology improvements. The LMS100™ system will consist of a single package and control system design from GE Energy, greatly enhancing reliability through commonality and simplicity.

The control system employs remote I/O (Input/Output) with the use of fiber optics for signal transmission between the package and control system. These connections are typically installed during site construction and have in the past been the source of many shutdowns due to Electro Magnetic Interference (EMI). The LMS100™ design reduces the number of these signal interconnects by 90% and eliminates EMI concerns with the use of fiber optic cables. In addition, the auxiliary skid design and location reduce the mechanical interconnects by 25%, further improving reliability. The use of an integrated system approach based on the latest reliability technology of the GE Transportation flight engine and GE Energy Frame GT will drive the Mean Time Between Forced Outages (MTBFO) of the LMS100™ system up to the best frame gas turbine rate.

The LMS100™ system has the same maintenance philosophy as aeroderivative gas turbines – modular design for field replacement. Design maintenance intervals are the same as the LM6000™ – 25,000 hours hot section repair and 50,000 hours overhaul intervals.

The LPC requires very little maintenance with only periodic borescope inspections at the same time as the core engine. No other significant maintenance is required.

The Supercore requires combustor, HPT airfoils and IPT airfoils inspection and on-condition repair or replacement at 25,000 hours. This can be accomplished on-site within a 4-day period. The package is designed for 24-hour removal and replacement of the Supercore. Rotable modules for the combustor, HPT and IPT will be used to replace existing hardware. The Supercore and PT rotor/stator module will be returned to the Depot for the 50,000-hour overhaul. During this period a leased Supercore and PT rotor/stator module will be available to continue revenue operation. The LMS100™ core is compatible with existing LM6000™ Depot capabilities.

The PT rotor/stator assembly only requires on-condition maintenance action at 50,000 hours. This module can be removed after the Supercore is removed and replaced with a new module or a leased module during this period.

The PT shaft assembly, like the LPC, needs periodic inspection only.

Configurations

The LMS100™ system is available as a Gas Turbine Generator set (GTG), which includes the complete intercooler system. An LMS100™ Simple Cycle power plant will also be offered. GTGs will be offered with several choices of combustor configurations as shown in Table 1.

The GTG is available for 50 and 60 Hz applications and does not require the use of a gearbox.

Air-to-air or air-to-water intercooler systems are available with any of the configurations to best match the site conditions.

Product Offering	Fuel Type	Diluent	NOx Level	Power Augmentation
LMS100PA-SAC (50 or 60 Hz)	Gas or Dual	Water	25	None
LMS100PA-SAC (50 or 60 Hz)	Gas	Steam	25	None
LMS100PA-SAC STIG (50 or 60 Hz)	Gas	Steam	25	Steam
LMS100PB-DLE2 (50 or 60 Hz)	Gas	None	25	None

Table 1. LMS100™ System Product Configurations

Optional kits will be made available for cold weather applications and power augmentation for hot ambient when using the air-to-air intercooler system.

All 50 Hz units will meet the requirements of applicable European directives (e.g. ATEX, PEDS, etc.).

The generator is available in an air-cooled or TWAC configuration and is dual rated (50 and 60 Hz). Sumitomo Corporation is a program participant in development of the LMS100™ system and will be supplying a portion of the production generators. Brush or others will supply generators not supplied by Sumitomo.

The GTG will be rated for 85-dBA average at 3 feet (1 meter). An option for 80-dBA average at 3 feet (1 meter) will be available.

Performance

The LMS100™ system cycle incorporates an intercooled compressor system. LPC discharge air is cooled prior to entering the HPC. This raises the specific work of the cycle from 150(kW/pps) to 210+(kW/pps). The LMS100™ system represents a significant shift in current power generation gas turbine technology (see Fig. 7 – data from Ref. 1).

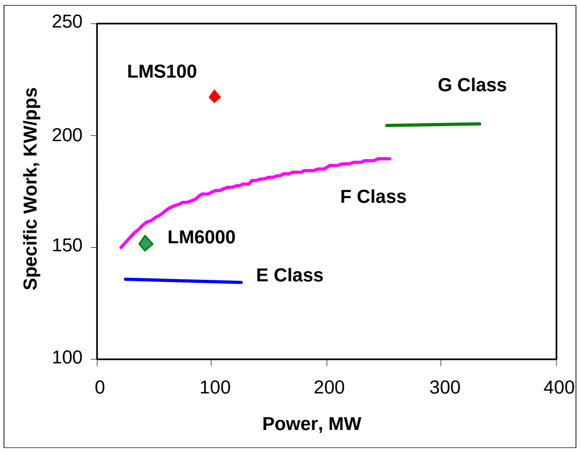

Fig. 7. LMS100™ System Specific Work vs. Other Technology

As the specific work increases for a given power the gas turbine can produce this power in a smaller turbine. This increase in technical capability leads to reduced cost. The LMS100™ system changes the game by shifting the technology curve to provide higher efficiency and power in a smaller gas turbine for its class (i.e. relative firing temperature level).

The cycle design was based on matching the existing GE Transportation CF6-80C2 compressor with available GE Energy compressor designs. The firing temperature was increased to the point allowed by the cooled high pressure air to maintain the same maximum metal temperatures as the LM6000™ gas turbine. The result is a design compression ratio of 42:1 and a firing temperature class of 2550°F (1380°C) that produces greater than 46% simple cycle gas turbine shaft efficiency. This represents a 10% increase over GE's highest efficiency gas turbine available in the Industry today – the LM6000™ gas turbine @42% (see Fig. 8 – data from Ref. 1).

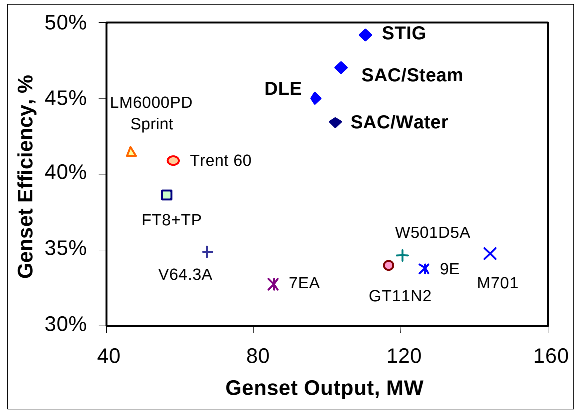

Fig. 8. LMS100™ System Competitive Positions

Intercooling provides unique attributes to the cycle. The ability to control the HPC inlet temperature to a desired temperature regardless of ambient temperatures provides operational flexibility and improved performance. The LMS100™ system with the SAC combustion system maintains a high power level up to an ambient temperature of ~80°F (27°C) (see Fig. 9). The lapse rate (rate of power reduction vs. ambient temperature) from 59°F (15°C) to 90°F (32°C) is only 2%, which is significantly less than a typical aeroderivative (~22%) or frame gas turbine (~12%).

The LMS100™ system has been designed for 50 and 60 Hz operations without the need for a speed reduction gearbox. This is achieved by providing a different PT Stage 1 nozzle for each speed that is mounted between the Supercore and PT. The PT design point is optimized to provide the best performance at both 3000 and 3600 rpm operating speeds. Fig. 9 shows that there is a very small difference in performance between the two operating speeds.

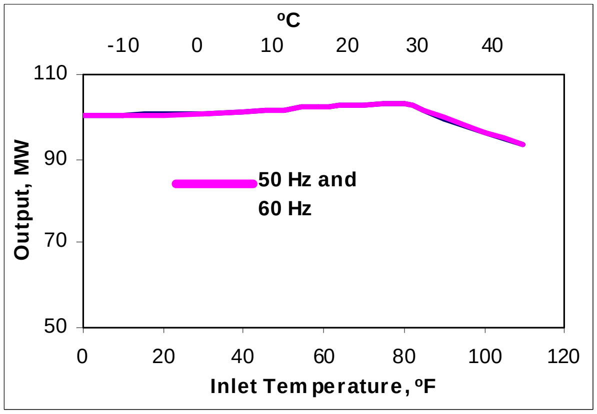

Fig. 9. LMS100™ System SAC Performance

Most countries today have increased their focus on environmental impact of new power plants and desire low emissions. Even with the high firing temperatures and pressures, the LMS100™ system is capable of 25ppm NOx at 15% O_2 dry. Table 1 shows the emission levels for each configuration. The 25 ppm NOx emissions from an LMS100™ system represent a 30% reduction in pounds of NOx/kWh relative to LM6000™ levels. The high cycle efficiency results in low exhaust temperatures and the ability to use lower temperature SCRs (Selective Catalytic Reduction).

Another unique characteristic of the LMS100™ system is the ability to achieve high part-power efficiency. Fig. 10 shows the part-power efficiency versus load. It should be noted that at 50% load the LMS100™ system heat rate (~40% efficiency) is better than most gas turbines at baseload. Also, the 59°F (15°C) and 90°F (32°C) curves are identical.

The LMS100™ system will be available in a STIG (steam injection for power augmentation) configuration providing significant efficiency improvements and power augmentation. Figs. 11 and 12 show the power output at the generator terminals and heat rate, respectively.

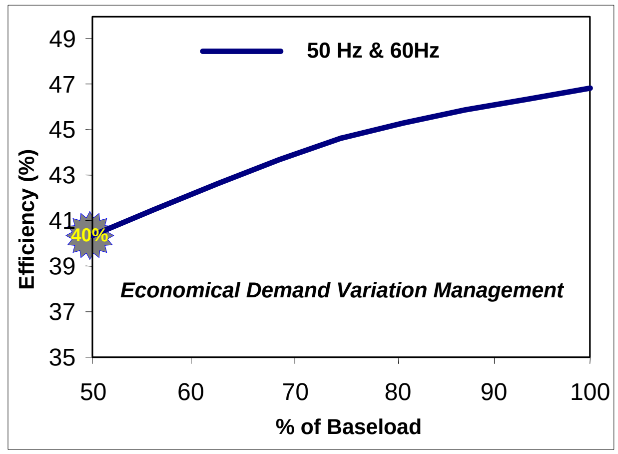

Fig. 10. LMS100™ System Part-Power Efficiency

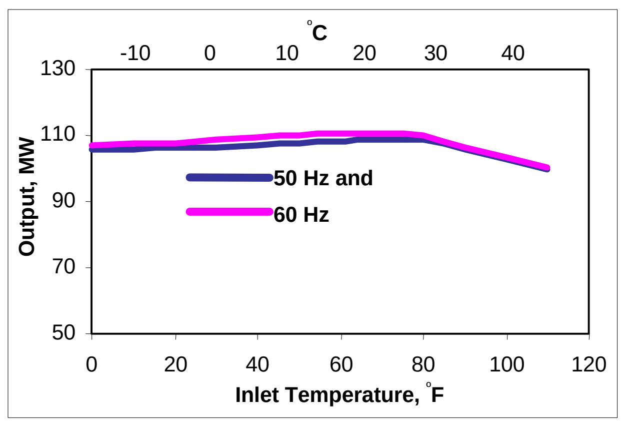

Fig. 11. LMS100™ System STIG Electric Power vs $T_{ambient}$

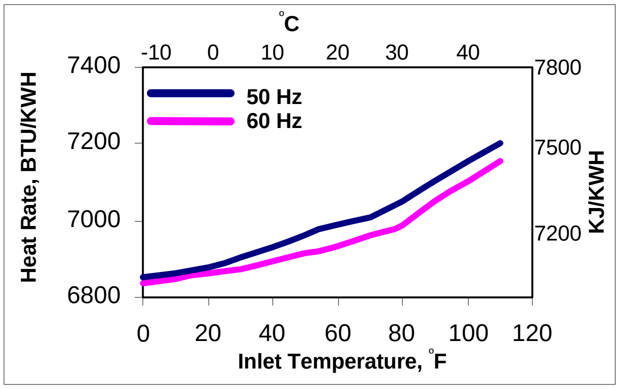

Fig. 12. **LMS100™ System STIG Heat Rate (LHV) vs $T_{ambient}$**

The use of STIG can be varied from full STIG to steam injection for NOx reduction only. The later allows steam production for process if needed. Fig. 13 – data from Ref. 1, compares the electrical power and steam production (@ 165 psi/365°F, 11.3 bar/185°C) of different technologies with the LMS100™ system variable STIG performance.

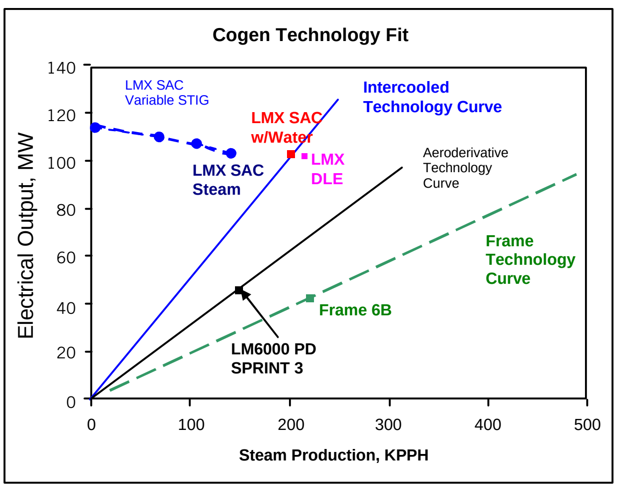

Fig. 13. **LMS100™ System Variable STIG for Cogen**

A unique characteristic of the LMS100™ system is that at >2X the power of the LM6000™ gas turbine it provides approximately the same steam flow. This steam-to-process can be varied to match heating or cooling needs for winter or summer, respectively. During the peak season, when power is needed and electricity prices are high, the steam can be injected into the gas turbine to efficiently produce additional power. During other periods the steam can be used for process. This characteristic provides flexibility to the customer and economic operation under varying conditions.

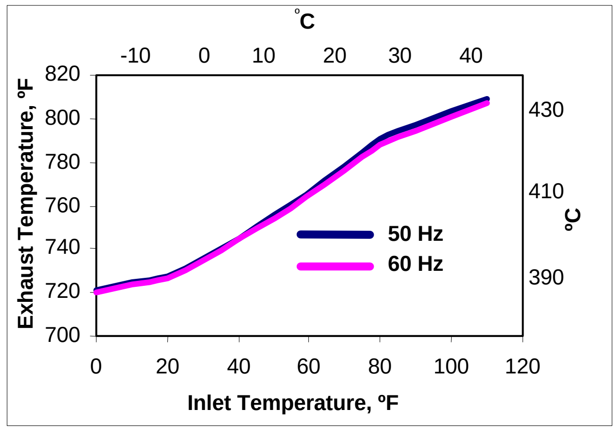

Fig. 14. **LMS100™ System Exhaust Temperatures**

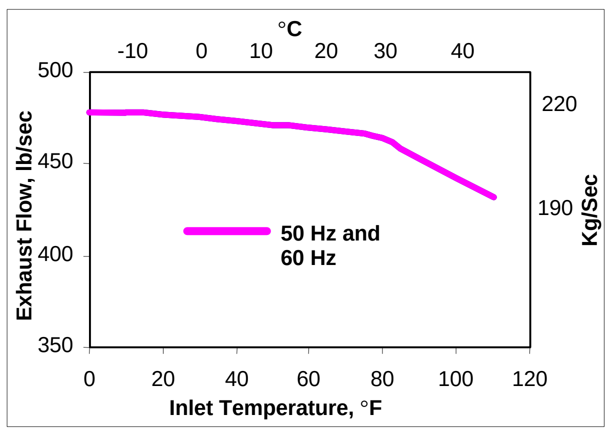

Fig. 15. **LMS100™ System Exhaust Flow**

The LMS100™ system cycle results in low exhaust temperature due to the high efficiency (see Figs. 14 and 15). Good combined cycle efficiency can be achieved with a much smaller steam plant than other gas turbines.

Table 2 shows a summary of the LMS100™ system configurations and their performance. The product flexibility provides the customer with multiple configurations to match their needs while at the same time delivering outstanding performance.

	Power (Mwe) 60 HZ	Heat Rate (BTU/KWh) 60 Hz	Power (Mwe) 50 HZ	Heat Rate (KJ/KWh) 50 Hz
DLE	98.7	7509	99.0	7921
SAC w/Water	102.6	7813	102.5	8247
SAC w/Steam	104.5	7167	102.2	7603
STIG	112.2	6845	110.8	7263

Table 2. LMS100™ System Generator Terminal Performance

(ISO 59°F/15°C, 60% RH, zero losses, sea level)

Simple Cycle

The LMS100™ system was primarily designed for simple cycle mid-range dispatch. However, due to its high specific work, it has low installed cost, and with no cyclic impact on maintenance cost, it is also competitive in peaking applications. In the 100 to 160MW peaking power range, the LMS100™ system provides the lowest cost-of-electricity (COE). Fig. 16 shows the range of dispatch and power demand over which the LMS100™ system serves as an economical product choice. This evaluation was based on COE analysis at $5.00/MMBTU (HHV).

The LMS100™ will be available in a DLE configuration. This configuration with a dry intercooler system will provide an environmental simple cycle power plant combining high efficiency, low mass emissions rate and without the usage of water.

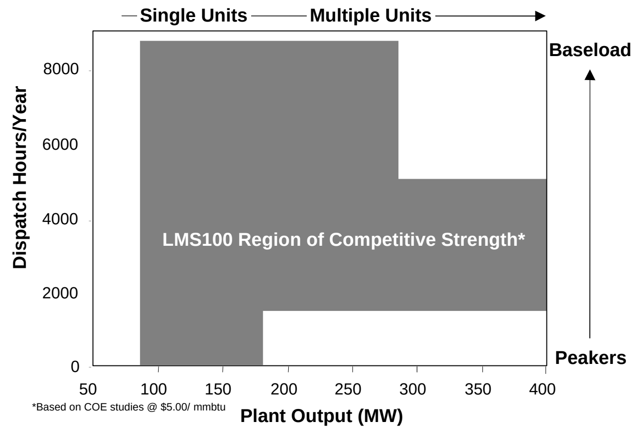

Fig. 16. LMS100™ System Competitive Regions

In simple cycle applications all frame and aeroderivative gas turbines require tempering fans in the exhaust to bring the exhaust temperature within the SCR material capability. The exhaust temperature (shown in Fig. 14) of the LMS100™ system is low enough to eliminate the requirement for tempering fans and allows use of lower cost SCRs.

Many peaking units are operated in hot ambient conditions to help meet the power demand when air conditioning use is at its maximum. High ambient temperatures usually mean lower power for gas turbines. Customers tend to evaluate gas turbines at 90°F (32°C) for these applications. Typically, inlet chilling is employed on aeroderivatives or evaporative cooling for heavy duty and aeroderivative engines to reduce the inlet temperature and increase power. This adds fixed cost to the power plant along with the variable cost adder for water usage. The power versus temperature profile for the LMS100™ system in

Fig. 9 shows power to be increasing to 80°F (27°C) and shows a lower lapse rate beyond that point versus other gas turbines. This eliminates the need for inlet chilling thereby reducing the product cost and parasitic losses. Evaporative cooling can be used above this point for additional power gain.

Simple cycle gas turbines, especially aeroderivatives, are typically used to support the grid by providing quick start (10 minutes to full power) and load following capability. The LMS100™ system is the only gas turbine in its size class with both of these capabilities. High part-power efficiency, as shown in Fig. 10, enhances load following by improving LMS100™ system operating economics.

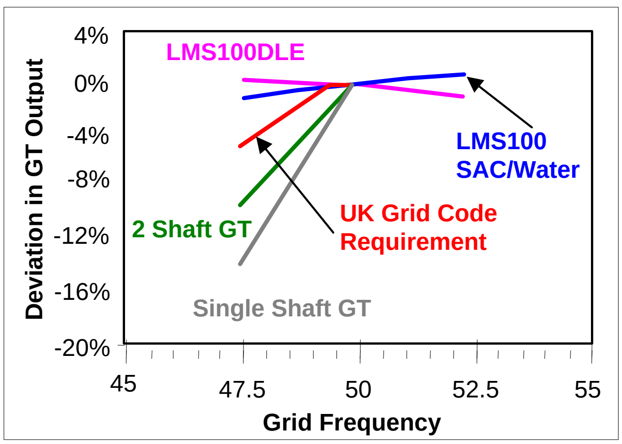

Fig. 17. LMS100™ System Gas Turbine Grid Frequency Variations

Many countries require off-frequency operation without significant power loss in order to support the grid system. The United Kingdom grid code permits no reduction in power for 1% reduction in grid frequency (49.5 Hz) and 5% reduction in power for an additional 5% reduction in grid frequency (47 Hz). Fig. 17 shows the impact of grid frequency variation on 3 different gas turbines: a single shaft, a 2-shaft and the LMS100™ system. Typically, a single and 2-shaft engine will need to derate power in order to meet the UK code requirements.

The LMS100™ system can operate with very little power variation for up to 5% grid frequency variation. This product is uniquely capable of supporting the grid in times of high demand and load fluctuations.

Combined Heat and Power

Combined Heat and Power (CHP) applications commonly use gas turbines. The exhaust energy is used to make steam for manufacturing processes and absorption chilling for air conditioning, among others. The LMS100™ system provides a unique characteristic for CHP applications. As shown in Fig. 13, the higher power-to-steam ratio can meet the demands served by 40-50MW aeroderivative and frame gas turbines and provide more than twice the power. From the opposite view, at 100MW the LMS100™ system can provide a lower amount of steam without suffering the significant efficiency reduction seen with similar size gas turbines at this steam flow. This characteristic creates opportunities for economical operation in conjunction with lower steam demand.

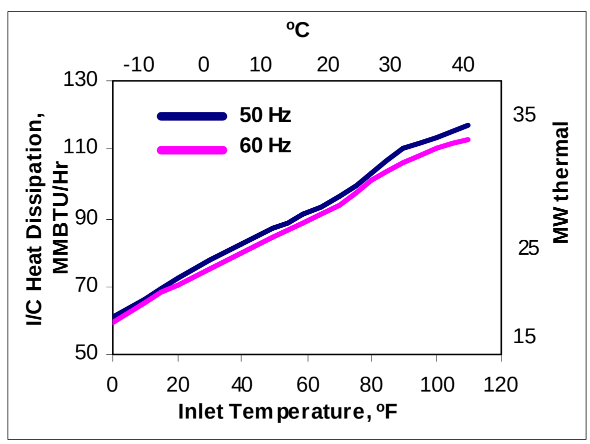

Fig. 18. LMS100™ System Intercooler Heat Rejections

Fig. 18 shows the intercooler heat dissipation, which ranges from 20-30MW of thermal energy. With an air-to-water intercooler system, the energy can be captured for low-grade steam or other applications, significantly raising the plant efficiency level. Using exhaust and intercooler energy, an LMS100™ plant will have >85% thermal efficiency.

Combined Cycle

Even though the LMS100™ system was aimed at the mid-range dispatch segment, it is also attractive in the combined cycle segment. Frame gas turbines tend to have high combined cycle efficiency due to their high exhaust temperatures. In the 80-160MW class, combined cycle efficiencies range from 51–54%. The LMS100™ system produces 120MW at 53.8% efficiency in combined cycle.

A combined cycle plant based on a frame type gas turbine produces 60-70% of the total plant power from the gas turbine and 30-40% from the steam turbine. In combined cycle the LMS100™ system produces 85-90% of the total plant power from the gas turbine and 10-15% from the steam turbine. This results in a lower installed cost for the steam plant.

The lower exhaust temperature of the LMS100™ system also allows significantly more power from exhaust system duct firing for peaking applications. Typical frame gas turbines exhaust at 1000°F-1150°F (538°C-621°C) which leaves 300°F-350°F (149°C-177°C) for duct firing. With the LMS100™ exhaust temperatures at <825°F (440°C) and duct-firing capability to 1450°F (788°C) (material limit) an additional 30MW can be produced.

Core Test

The LMS100™ core engine will test in GE Transportation's high altitude test cell in June 2004. This facility provides the required mass flow at >35 psi (>2 bar) approaching the core inlet conditions. The compressor and turbine rotor and airfoils will be fully instrumented. The core engine test will use a SAC dual fuel combustor configuration with water injection. Testing will be conducted on both gas and liquid fuel. This test will validate HPC and HPT aeromechanics, combustor characteristics, starting and part load characteristics, rotor mechanical design and aero thermal conditions, along with preliminary performance. More than 1,500 sensors will be measured during this test.

Full Load Test

The full load test will consist of validating performance (net electrical) of the gas turbine intercooler system with the production engine configuration and air-cooled generator. All mechanical systems and component designs will be validated together with the control system. The gas turbine will be operated in both steady state and transient conditions.

The full load test will be conducted at GE Energy's aeroderivative facility in Jacintoport, Texas, in the first half of 2005. The test will include a full simple cycle power plant operated to design point conditions. Power will be dissipated to air-cooled load (resistor) banks. The gas turbine will use a SAC dual fuel combustion system with water injection.

The LPC, mid-shaft, IPT and PT rotors and airfoils will be fully instrumented. The intercooler system, package and sub-systems will also be instrumented to validate design calculations. In total, over 3,000 sensors will be recorded.

After testing is complete, the Supercore and PT rotor/stator assemblies will be replaced with production (uninstrumented) hardware. The complete system will be shipped to the demonstration customer site for endurance testing. This site will be the "Fleet Leader," providing early evaluation of product reliability.

Schedule

The first production GTG will be available for shipment from GE Energy's aeroderivative facility in Jacintoport, Texas, in the second half of 2005. Configurations available at this time will be SAC gas fuel, with water or steam injection, or dual fuel with water injection. Both configurations will be available for 50 and 60 Hz applications. STIG will be available in the first half of 2006. The DLE2 combustion system development is scheduled to be complete in early 2006. Therefore, a LMS100™ system configured with DLE2 combustor in 50 or 60 Hz will be available in the second half of 2006.

Summary

The LMS100™ system provides significant benefits to power generation operators as shown in Table 3. The LMS100™ system represents a significant change in power generation technology. The marriage of frame technology and aircraft engine technology has produced unparalleled simple cycle efficiency and power generation flexibility. GE is the only company with the technology base and product experience to bring this innovative product to the power generation industry.

- High simple cycle efficiency over a wide load range
- Low lapse rate for sustained hot day power
- Low specific emissions (mass/kWh)
- 50 or 60 Hz capability without a gearbox
- Fuel flexibility – multiple combustor configurations
- Flexible power augmentation
- Designed for cyclic operation:
  - No maintenance cost impact
- 10-minute start to full power
  - Improves average efficiency in cyclic applications
  - Potential for spinning reserves credit
  - Low start-up and shutdown emissions
- Load following capability
- Synchronous condenser operation
- High availability:
  - Enabled by modular design
  - Rotable modules
  - Supercore and PT lease pool
- Low maintenance cost
- Designed for high reliability
- Flexible plant layout
  - Left- or right-hand exhaust and/or intercooler installation
- Operates economically across a wide range of dispatched hours

Table 3. LMS100™ Customer Benefits

References:

1) Gas Turbine World (GTW); "2003 GTW Handbook," Volume 23