Golden Spread
Electric Cooperative, Inc.
A Touchstone Energy® Cooperative

AIR PERMITS DIVISION

JUL 15 2014

HAND-DELIVERED

July 15, 2014

Mr. Jeffrey Robinson
Chief, Air Permits Section
U.S. Environmental Protection Agency
Region 6 (6PD-R)
1445 Ross Avenue
Dallas, TX 75202-2733

Mr. Mike Wilson, P.E. (MC-163)
Director, Air Permits
Texas Commission on Environmental Quality
12100 Park 35 Circle, Building C
Austin, Texas 78753

Re: Application for Amendment of Prevention of Significant Deterioration (PSD)
Air Quality Permit PSD-TX-1358-GHG
Authorization to Construct 3 Gas Turbine Facilities
Golden Spread Electric Cooperative, Inc.
Antelope Elk Energy Center, Abernathy, Hale County, Texas

Dear Messrs. Robinson and Wilson:

Golden Spread Electric Cooperative, Inc. (GSEC) is submitting the enclosed application to amend its PSD permit for Antelope Elk Energy Center (AEEC) near Abernathy in Hale County, Texas. AEEC currently comprises 18 gas-fired engine generators. The referenced permit currently authorizes the construction of a GE 7F 5-Series gas turbine in a simple-cycle application. Field construction of that unit is underway. That unit is intended to provide system capacity needs starting in early 2015.

This new permit amendment application is to authorize the construction of three identical gas turbines to meet expected electrical power needs starting in early 2016. Power from the unit under construction, plus 1-2 of the units proposed in this amendment, will be used to provide emergency and other power to GSEC's cooperative members as well as to the Southwest Power Pool and Electric Reliability Council Of Texas.

GSEC requests that the review of this permit application and issuance of a permit be completed by the 1st quarter of 2015 to enable construction to commence and be completed by the first quarter of 2016. Production from these units is critical to meet predicted system power needs arising from the termination of existing power supply contracts and demands in 2016 and later years. Since the proposed units are virtually identical to the unit whose permit to construct was issued on June 3, 2014, we hope that the permit amendment review can be facilitated and expedited.

As shown in the permit application, the proposed units are subject to EPA PSD review for GHG pollutants. Several other non-GHG air pollutants are also subject to PSD review under the rules of the Texas Commission on Environmental Quality (TCEQ). A PSD permit application covering those pollutants, and other pollutants not subject to PSD review, is simultaneously being submitted to TCEQ.

However, subject to final approval of the Texas SIP program to review GHG pollutants, we expect and request that the TCEQ conduct the review of GHG pollutants.

GSEC hopes for an expeditious review of its application and is committed to working closely with your staff to answer questions and address issues as they arise. Our air quality consultant, Pat Murin, can be contacted any time to respond to questions and issues. His contact information is included in the Administrative section of the permit application. I and other GSEC technical and management staff also are available to respond to questions and issues that may develop during the permit application review process.

We look forward to working with both EPA and TCEQ as you review our permit application and develop a permit that meets the requirements of the permit program.

Sincerely yours,

George E. Hess
Vice President of Production
Golden Spread Electric Cooperative, Inc.

Enclosure

Application to Amend
Prevention of Significant Deterioration Permit
PSD-TX-1358-GHG
Antelope Elk Energy Center
Golden Spread Electric Cooperative, Inc.
Abernathy, Texas

Submitted to:

U.S. Environmental Protection Agency, Region 6
Dallas, TX

and

Texas Commission on Environmental Quality
Austin, TX

July 2014

TABLE OF CONTENTS

PAGE NO.

1.0 Introduction and Administrative Information 1
2.0 Process Description and Process Flow Diagram 12
3.0 Site Information 14
4.0 Greenhouse Gas Emissions 17
- 4.1 Gas Turbines 17
- 4.2 Natural Gas Line Fugitives 17
- 4.3 SF_6 Leaks from Circuit Breakers 17
- 4.4 Backup/Emergency Diesel Generators 17
- 4.5 Natural Gas Heaters 18

5.0 PSD Applicability Summary 25
6.0 Best Available Control Technology 27
- 6.1 Gas Turbines 27
- 6.2 Natural Gas Line Fugitives 32
- 6.3 SF_6 Leaks from Circuit Breakers 33
- 6.4 Backup/Emergency Diesel Generators 34
- 6.5 Natural Gas Heaters 35
- 6.6 Proposed Emission & Production Limits, Monitoring, and Maintenance Requirements 36

The seal appearing on this document was authorized by Patrick J. Murin, P.E. 67271 on 7/9/2014
P.E. Expiration Date: 12/31/2014

Murin Environmental Inc.
TBPE Registration No. F-7702
Firm Registration Expiration Date: 3/31/2015

1.0 INTRODUCTION AND ADMINISTRATIVE INFORMATION

Golden Spread Electric Cooperative, Inc. (GSEC) is a tax-exempt, consumer-owned public utility, organized in 1984 to provide low cost, reliable electric service for its rural distribution cooperative members. Its 16 member systems serve more than 199,000 retail consumers located in the Oklahoma Panhandle and an area covering 24 percent of Texas including the Panhandle, South Plains and Edwards Plateau Regions.

Golden Spread Electric Cooperative, Inc. (GSEC) owns and operates Antelope Elk Energy Center (AEEC), a 168 MW generating facility currently comprising 18 quick start Wartsilla engines located near Abernathy, Texas. At AEEC, GSEC is also currently building a new combustion turbine-generator facility with a maximum generating capacity of 202 MW, whose construction was recently authorized under Permit PSD-TX-1358-GHG. These facilities provide primarily peaking and intermediate power needs in a highly cyclical operation, and are used also to provide quick-start capacity and grid stabilization to existing and planned wind turbine facilities. In this project, GSEC proposes to build three additional gas turbine facilities identical to the facility currently in construction. These new units will support demands from both the Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP), with one or two of the units configured to support either grid.

The new units at Antelope Elk Energy Center will feature new GE 7F 5-Series gas turbines in a simple cycle application.[1] Supply air will be compressed by the integral 14-stage compressor. Natural gas fuel will be combusted in GE's DLN 2.6+ combustion system and the combustion exhaust gases will power the 3-stage expansion turbine. The turbine is air cooled, and an evaporative air cooler is also used for inlet air cooling during summer peak ambient air temperatures.

The 7F 5-Series turbine is the latest development of GE's F-class turbine technology, which is used in over 1100 gas turbines worldwide. The 14-stage air compressor is equipped with super-finish 3-dimensional airfoils for improved efficiency with less long-term degradation. The 3-stage combustion turbine in the 5-Series features a hot gas path with advanced cooling and sealing technologies to improve efficiency and lower lifecycle costs. A new model-based process control system also improves performance efficiency. As a result, the 7F 5-Series turbine achieves efficiency above 38.7% in a simple-cycle application[2]. The unit can produce up to 202 MW in cold weather conditions, and nominally 190.1 MW in peak summer operation. Compared to other 7F class turbines, the 5-Series turbine also has improvements in start-up and turndown capability, ramp-up rate, and lifecycle costs in peaking, cyclic, and steady-state operation. During normal start-up, the 5-Series turbine will achieve 50% capacity load in 30 minutes, and thereafter operate at design emission limits. During "peaking start-up", a combination of measures allow the unit to achieve 75% load in about 10 minutes, full load operation in about 11.5 minutes, and to operate within design emission limits within 22 minutes. (Peaking start-ups increase the rotor and hot gas maintenance costs relative to normal start-ups.) The turbine is equipped with GE's Dry Low NOx (DLN) 2.6+ combustion system to achieve normal emission levels of 9 ppmvd nitrogen oxides (NOx) @15% O_2 and 9 ppmvd carbon monoxide (CO) at operation from 100% load to nominally 50% load.

Combustion exhaust emissions from the turbines comprise the majority of greenhouse gas (GHG) emissions from the plant site, with smaller emissions from the natural gas supply equipment, natural gas

[1] These units were previously designated as 7FA.005 series turbines.
[2] This efficiency is equivalent to a heat rate of 8905 BTU (LHV)/kWh of gross power output, and is guaranteed at 98°F ambient temperatures and 18% relative humidity and other specified operating conditions and parameters.

heaters, emergency/backup diesel generators, and electrical equipment. The proposed gas turbines will exhaust through stack Emission Point Numbers (EPNs) TURB2, TURB3, and TURB4. Leaks from the natural gas supply equipment are shown as EPN NG-FUG. Sulfur hexafluoride (SF_6) will be released in low-volume leaks from circuit breakers as EPN SF_6-FUG. The natural gas heaters are indirect-fired water batch heaters used to heat the natural gas fuel above the dewpoint. They are fueled with natural gas and discharge through EPNs NGHEATR-2A, NGHEATR-3, and NGHEATR-4. The emergency/backup diesel generators discharge through EPNs EMERGEN2, EMERGEN3, and EMERGEN4.

Under the U.S. Environmental Protection Agency's (EPA's) Prevention of Significant Deterioration (PSD) regulations in 40 CFR 52.21, Antelope Elk Energy Center is currently a major source of both GHG and "criteria" (non-GHG) pollutants. Under the current PSD rules and guidance, the project to install three gas turbines and associated equipment at Antelope Elk Energy Center is required to obtain authorization for its GHG emissions from the EPA. (A State Implementation Plan to enable Texas to directly review and process GHG permit applications is pending.) The proposed project is also subject to PSD review by the Texas Commission on Environmental Quality (TCEQ) for non-GHG emissions, since it will release carbon monoxide (CO), nitrogen oxides (NOx), particulate matter less than 10 microns in diameter and less than 2.5 microns in diameter at rates above their PSD significant emission rates. These non-GHG emissions, and other pollutants with emission rates below the respective PSD significant emission rates, are subject to the State of Texas pre-construction authorization requirements, and authorizations for those associated facilities and emissions will be obtained separately from the TCEQ.

Sources and emissions subject to PSD permitting requirements because of their potential to release GHG emissions are only subject to some of the requirements of the PSD rules. The primary requirement of a PSD permit for GHG emissions is to require that the permitted facilities use the Best Available Control Technology (BACT) for controlling GHG emissions. The resulting PSD permit specifies emission levels reflecting the use of BACT, including emissions monitoring and other requirements to ensure that the BACT emission levels are maintained during operations.

Administrative information for the owner and operator of the Antelope Elk Energy Center, and information on the site itself, is provided in the TCEQ Form PI-1, which follows this page. The TCEQ Form PI-1 is a basic element of the TCEQ permit process which will be used to authorize emissions and facilities other than those related to GHG pollutants.

The start of construction of the new turbine at Antelope Elk Energy Center is projected for March 1, 2015. Initial operation of the new facilities is expected in 1st quarter 2016.

The remaining sections of this permit application are the following: Section 2.0 provides process information for the new turbine and Section 3.0 provides site information for Antelope Elk Energy Center. Section 4.0 summarizes and describes the calculation of GHG emissions from the proposed turbine and supporting equipment. Section 5.0 summarizes the applicability of PSD permit requirements. Section 6.0 analyzes and selects the BACT, including proposed emission limits and monitoring and maintenance requirements to achieve and maintain compliance with the BACT emission limits.

Affiliated with the Federal PSD permit process are requirements to consider the impacts of the proposed power plant on cultural and historical resources in the area, and on biological resources including threatened and endangered species. These impacts will be addressed in studies separate from this PSD permit application.

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: **Golden Spread Electric Cooperative, Inc.**		
Texas Secretary of State Charter/Registration Number (if applicable): **SOS Filing No. 68655501**		
B. Company Official Contact Name: **George E. Hess**		
Title: **Vice President, Production**		
Mailing Address: **P.O. Box 9898**		
City: **Amarillo**	State: **TX**	ZIP Code: **79105-5898**
Telephone No.: **806/349-5218**	Fax No.: **806/374-2922**	E-mail Address: **ghess@gsec.coop**
C. Technical Contact Name: **Patrick Murin, P.E.**		
Title: **Principal**		
Company Name: **Murin Environmental Inc.**		
Mailing Address: **7052 West Mayberry Trail**		
City: **Peoria**	State: **AZ**	ZIP Code: **85383-3168**
Telephone No.: **713/819-6115**	Fax No.:	E-mail Address: **pmurin@murinenv.com**
D. Site Name: **Antelope Elk Energy Center**		
E. Area Name/Type of Facility: **Turbines 2-4/Electrical Power Production**	☒ Permanent ☐ Portable	
F. Principal Company Product or Business: **Electrical Power Production**		
Principal Standard Industrial Classification Code (SIC): **4911**		
Principal North American Industry Classification System (NAICS): **221112**		
G. Projected Start of Construction Date: **3/1/2015**		
Projected Start of Operation Date: **1st Q/2016**		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.): **Facility is north off County Road 315, east of I-27**		
Street Address: **1454 County Road 315**		
City/Town: **Abernathy**	County: **Hale**	ZIP Code: **79311**
Latitude (nearest second): **33°51'56.5"N**	Longitude (nearest second): **101°50'37.6"W**	

I.	**Applicant Information (continued)**	
I.	Account Identification Number (leave blank if new site or facility): **HAA-002B**	
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): **CN602663387**	
L.	Regulated Entity Number (RN): **RN105862510**	
II.	**General Information**	
A.	Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.	☐ YES ☒ NO
B.	Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES ☒ NO
C.	Number of New Jobs: **N/A**	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: **Senator Robert Duncan**		District No.: **28**
State Representative: **Representative Ken King**		District No.: **88**
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): **109148 / PSDTX1358**	
C.	Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)*	
☒ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit		
☒ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source		
☐ Other:		
D.	Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

III.	**Type of Permit Action Requested *(continued)***		
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.0			☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO", attach detailed information.			☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?			☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.			
List: **None**			
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.): **An initial FOP application will be submitted.**			
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.			
☒ FOP Significant Revision	☐ FOP Minor	☐ Application for an FOP Revision	
☐ Operational Flexibility/Off-Permit Notification		☐ Streamlined Revision for GOP	
☐ To be Determined		☐ None	

III.	**Type of Permit Action Requested *(continued)***	
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2.	Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***	
☐ GOP Issued	☐ GOP application/revision application submitted or under APD review	
☒ SOP Issued	☒ SOP application/revision application submitted or under APD review	
IV.	**Public Notice Applicability**	
A.	Is this a new permit application or a change of location application?	☐ YES ☒ NO
B.	Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C.	Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☒ YES ☐ NO
D.	Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES ☒ NO
If Yes, list the affected state(s) and/or Class I Area(s).		
List:		
E.	Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.	
1.	Is there any change in character of emissions in this application?	☐ YES ☒ NO
2.	Is there a new air contaminant in this application?	☐ YES ☒ NO
3.	Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☒ NO
F.	List the total annual emission increases associated with the application	
Volatile Organic Compounds (VOC): **95.69 tons/yr**		
Sulfur Dioxide (SO2): **37.45 tons/yr**		
Carbon Monoxide (CO): **785.64 tons/yr**		
Nitrogen Oxides (NOx): **427.57 tons/yr**		
Particulate Matter (PM): **64.20 tons/yr**		
PM 10 microns or less (PM10): **64.20 tons/yr**		
PM 2.5 microns or less (PM2.5): **64.20 tons/yr**		
Lead (Pb): < **0.0001 tons/yr**		
Hazardous Air Pollutants (HAPs): **13.69 tons/yr**		
Other speciated air contaminants not listed above: **GHG as CO2-eq – 1,622,386 tons/yr**		

TCEQ

V. Public Notice Information *(complete if applicable)*		
A. Public Notice Contact Name: **Ron Popejoy**		
Title: **Production Environmental & IS Coordinator**		
Mailing Address: **4717 S. Loop 289**		
City: **Lubbock**	State: **TX**	ZIP Code: **79424**
B. Name of the Public Place: **Abernathy Public Library**		
Physical Address *(No P.O. Boxes)*: **811 Avenue D**		
City: **Abernathy**	County: **Hale**	ZIP Code: **79311**
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: **Judge Bill Coleman**		
Mailing Address: **Courthouse, 500 Broadway, Room 240**		
City: **Plainview**	State: **TX**	ZIP Code: **79072-8050**
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located.		
Chief Executive:		
Mailing Address:		
City:	State:	ZIP Code:
Name of the Indian Governing Body:		
Mailing Address:		
City:	State:	ZIP Code:

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

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

VII.	**Technical Information**			
C.	Maximum Operating Schedule:			
Hour(s): **24**	Day(s): **7**	Week(s): **52**	Year(s): **up to 8760 hrs**	
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

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
Is the estimated capital cost of the project greater than $2 million dollars?		☒ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.		
XI.	**Permit Fee Information**	
Check, Money Order, Transaction Number ,ePay Voucher Number:		Fee Amount: **$75,000**
Paid online?		☐ YES ☒ NO
Company name on check: **Golden Spread Electric Cooperative, Inc.**		
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? **Not required since maximum permit fee is paid.**		☐ YES ☐ NO ☒ N/A

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

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: **George E. Hess**
Signature: ______ *Original Signature Required*
Date: 7-9-14

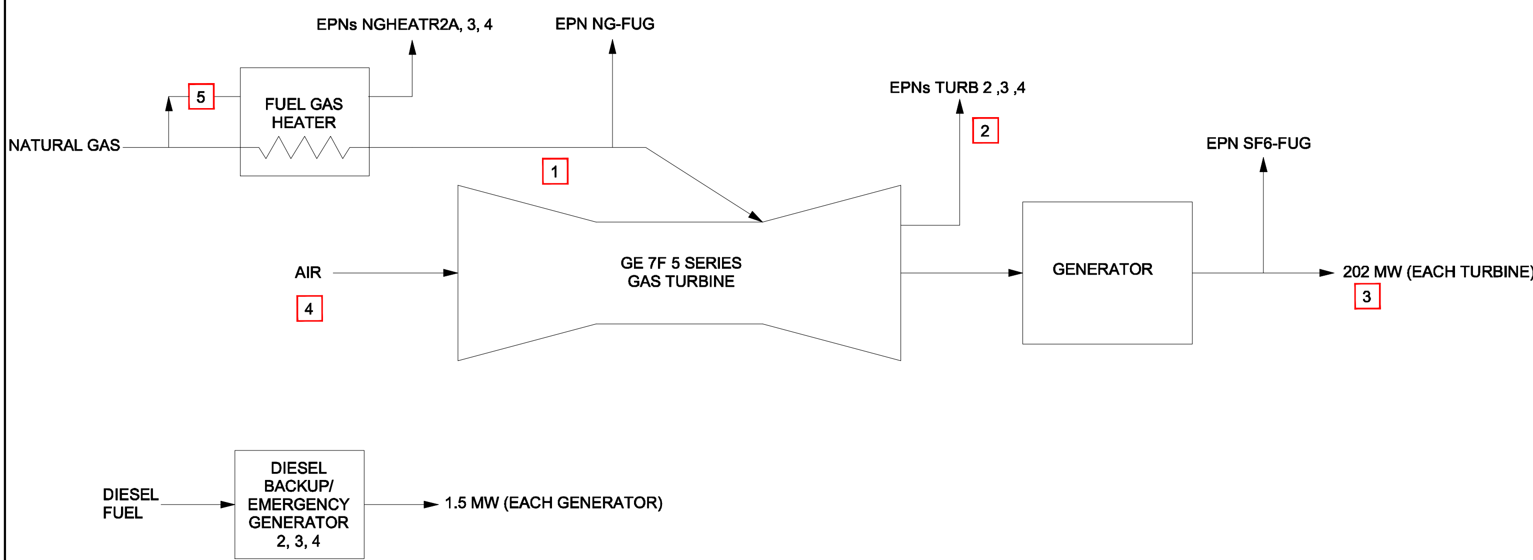
2.0 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

The process flow diagram illustrates the process steps in the proposed gas turbine systems.

The proposed gas turbines will be a GE 7F 5-Series gas-fired combustion turbine. Supply air will be compressed by the integral 14-stage compressors. Natural gas fuel will be combusted in GE's DLN 2.6+ combustion system and the combustion exhaust gases will power the 3-stage expansion turbine. The turbine is air cooled, and an evaporative air cooler and/or chiller is also used for inlet air cooling during summer peak ambient air temperatures.

The proposed gas turbines will exhaust through stack Emission Point Numbers (EPNs) TURB2, TURB3, and TURB4. Leaks from the natural gas supply equipment are shown as EPN NG-FUG. Sulfur hexafluoride (SF_6) will be released in low-volume leaks from circuit breakers as EPN SF_6-FUG. The natural gas heaters are indirect-fired water batch heaters used to heat the natural gas fuel above the dewpoint. They are fueled with natural gas and discharge through EPNs NGHEATR-2A, NGHEATR-3, and NGHEATR-4. The emergency/backup diesel generators discharge through EPNs EMERGEN2, EMERGEN3, and EMERGEN4. Non-GHG emissions will not be covered in this permit.

PROCESS FLOW DIAGRAM



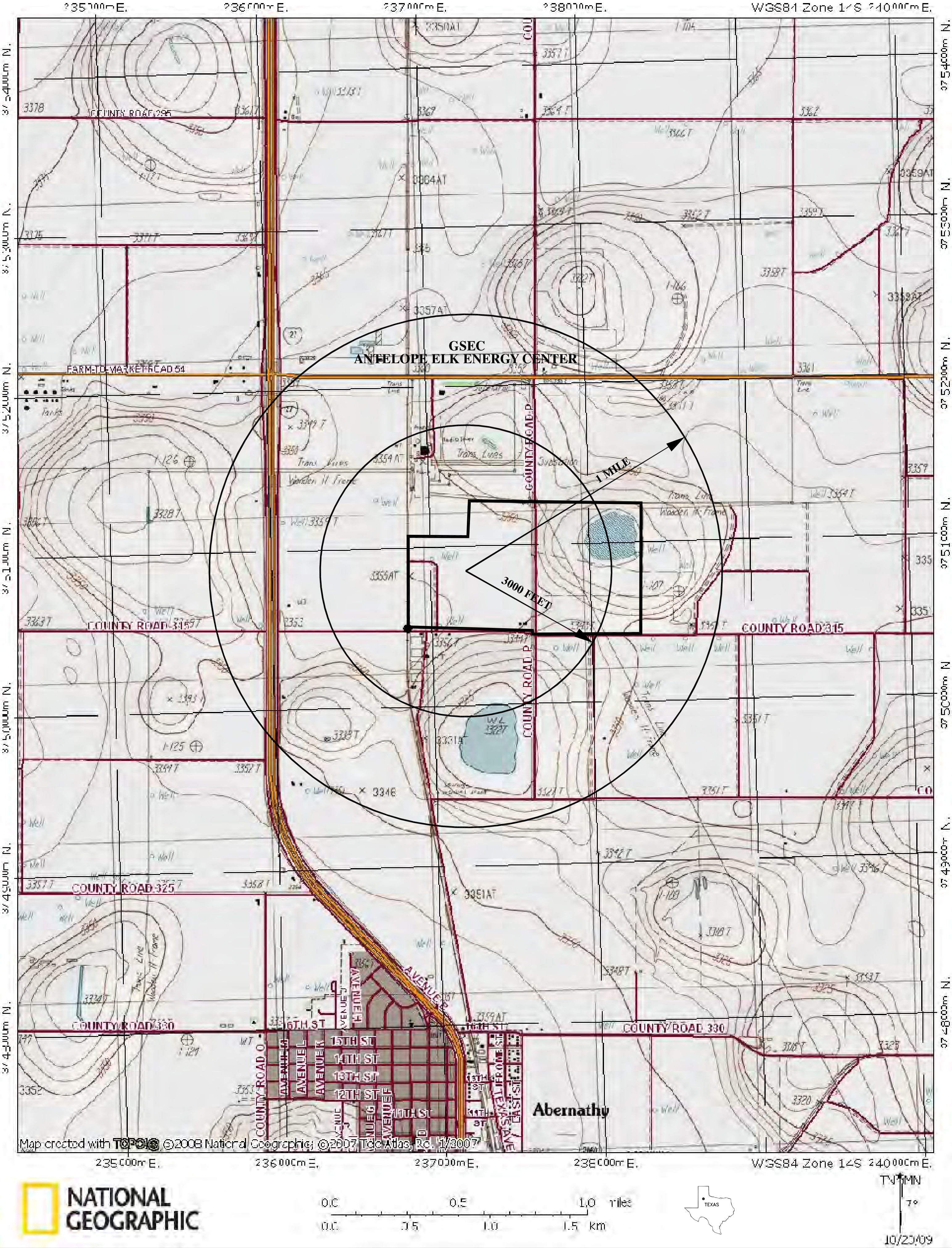
Drawn By	Eng. By	Date		REV
DWW	PJM	12/19/12 - 7/2/14	GSEC - Antelope	5
H:\Clients\MUR4615\GSEC-ANTALOPE\FLOW			Name FLOW	

3.0 SITE INFORMATION

As shown in the Area Map, Antelope Elk Energy Center is located north of County Road 315, east of I-27 in Hale County, Texas. The location is approximately 1.6 miles north of the City of Abernathy.

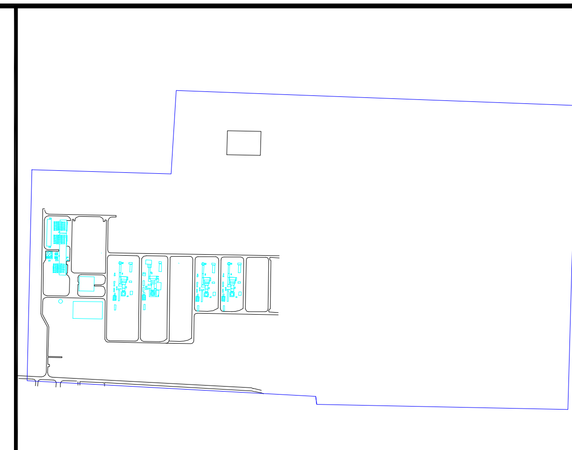
The preliminary plot plan shows the location of the proposed units at Antelope.

33°51'52" N, 101°50'24" W WGS84 Map rev. 1985 Abernathy, TX

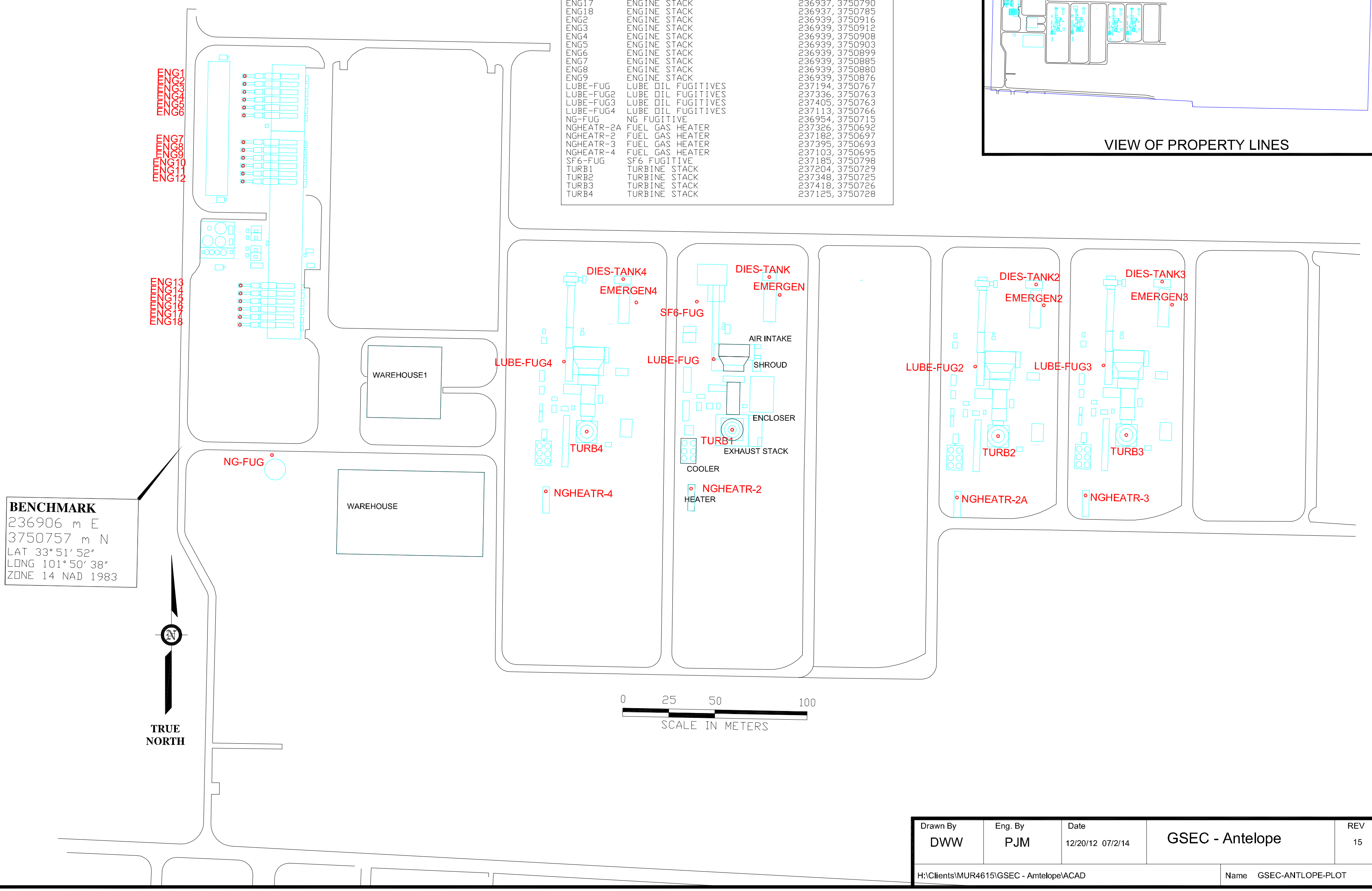


Downwash Structure Name	Height (feet)	Height (meters)	Dimensions (meters)
AIR INTAKE	74.0	22.56	16.60 x 6.61
COOLER	12.0	3.66	8.40 x 13.50
ENCLOSER	26.0	7.92	7.00 x 17.50
EXHAUST STACK	170.0	51.82	Diameter 11.98
HEATER	15.0	4.57	3.70 x 14.30
SHROUD	50.0	15.24	16.40 x 3.30
WAREHOUSE	28.0	8.53	79.32 x 45.81
WAREHOUSE1	28.0	8.53	40.01 x 39.01

Emission Point Number	Name	Location Easting, Northing (meters)
DIES-TANK	DIES TANK	237224, 3750811
DIES-TANK2	DIES TANK	237369, 3750807
DIES-TANK3	DIES TANK	237437, 3750809
DIES-TANK4	DIES TANK	237145, 3750810
EMERGEN	EMERGENCY DIESEL GENERATOR	237230, 3750802
EMERGEN2	EMERGENCY DIESEL GENERATOR	237373, 3750796
EMERGEN3	EMERGENCY DIESEL GENERATOR	237442, 3750796
EMERGEN4	EMERGENCY DIESEL GENERATOR	237152, 3750798
ENG1	ENGINE STACK	236939, 3750920
ENG10	ENGINE STACK	236939, 3750872
ENG11	ENGINE STACK	236938, 3750868
ENG12	ENGINE STACK	236938, 3750863
ENG13	ENGINE STACK	236937, 3750807
ENG14	ENGINE STACK	236937, 3750803
ENG15	ENGINE STACK	236937, 3750798
ENG16	ENGINE STACK	236937, 3750794
ENG17	ENGINE STACK	236937, 3750790
ENG18	ENGINE STACK	236937, 3750785
ENG2	ENGINE STACK	236939, 3750916
ENG3	ENGINE STACK	236939, 3750912
ENG4	ENGINE STACK	236939, 3750908
ENG5	ENGINE STACK	236939, 3750903
ENG6	ENGINE STACK	236939, 3750899
ENG7	ENGINE STACK	236939, 3750885
ENG8	ENGINE STACK	236939, 3750880
ENG9	ENGINE STACK	236939, 3750876
LUBE-FUG	LUBE OIL FUGITIVES	237194, 3750767
LUBE-FUG2	LUBE OIL FUGITIVES	237336, 3750763
LUBE-FUG3	LUBE OIL FUGITIVES	237405, 3750763
LUBE-FUG4	LUBE OIL FUGITIVES	237113, 3750766
NG-FUG	NG FUGITIVE	236954, 3750715
NGHEATR-2A	FUEL GAS HEATER	237326, 3750692
NGHEATR-2	FUEL GAS HEATER	237182, 3750697
NGHEATR-3	FUEL GAS HEATER	237395, 3750693
NGHEATR-4	FUEL GAS HEATER	237103, 3750695
SF6-FUG	SF6 FUGITIVE	237185, 3750798
TURB1	TURBINE STACK	237204, 3750729
TURB2	TURBINE STACK	237348, 3750725
TURB3	TURBINE STACK	237418, 3750726
TURB4	TURBINE STACK	237125, 3750728



VIEW OF PROPERTY LINES



Drawn By	Eng. By	Date		REV
DWW	PJM	12/20/12 07/2/14	GSEC - Antelope	15
H:\Clients\MUR4615\GSEC - Amtelope\ACAD			Name GSEC-ANTLOPE-PLOT	

4.0 GHG EMISSIONS

As noted in the Process Description, the new sources of GHG emissions on the site will include the following:

- The combustion turbines
- Natural gas line equipment fugitive releases
- SF_6 leaks from circuit breakers
- Backup/emergency diesel generators
- Natural gas heaters

GHG emissions from these sources are summarized in Table 1. The bases for and calculations of these emissions are further discussed below and in Tables 2 through 6. The new turbines at Antelope Elk Energy Center will not emit two of the six pollutant categories which comprise GHG pollutants, namely hydrofluorocarbons or perfluorocarbons. The plant will emit some amount of each of the remaining four categories of GHG pollutants (CO_2, CH_4, N_2O, and SF_6), but emissions of CO_2 comprise 98.7% of the total annual tons of GHG pollutants as CO_2-e, and 99.97% of the mass emissions of GHG pollutants.

4.1 Gas Turbines

GHG emissions from the combustion turbines comprise CO_2, CH_4, and N_2O. Emissions of CO_2 and CH_4 during normal operations are those estimated from turbine manufacturer data. Emissions of N_2O are estimated from the EPA's *Compilation of Air Pollutant Emission Factors* (AP-42, 5th Edition) and the maximum fuel usage rates. GHG emissions of CO_2 and N_2O during startup and shutdown operations were conservatively estimated to be the same as those in normal operations. CH_4 emissions during startup and shutdown operations were estimated from turbine manufacturer data. Actual GHG emissions in these operations will be less, based on the lower firing rate of natural gas. Table 2 provides the emission calculation bases and example calculations.

4.2 Natural Gas Line Fugitives

Natural gas line fugitive emissions are determined from the number of pipeline components such as control and relief valves, flanges, and sampling connections, and emission factors in 40 CFR 98 Table W-1A. The speciation of the fugitive releases uses data on the maximum composition of GHG components in the natural gas supply. Table 3 provides the emission calculation bases and example calculations.

4.3 SF_6 Leaks from Circuit Breakers

Leaks of SF_6 are based on the amount of SF_6 in circuit breakers at the power plant and a standard leak rate of 0.5% per year, which corresponds to the use of modern design circuit breakers and a comprehensive leak monitoring program. Table 4 provides the emission calculation bases and example calculations.

4.4 Backup/Emergency Diesel Generators

GHG emissions from the emergency generator are based on the vendor maximum fuel usage rates and vendor emission factors, excepting that emission factors from AP-42 were used for emissions of CO_2. Table 5 provides emission calculation bases and example calculations.

4.5 Natural Gas Heaters

Emissions from the natural gas heaters are based on the maximum fuel firing rate and emission factors from AP-42. Table 6 provides emission calculation bases and example calculations.

Maximum Emission Increases

	Turbines 2, 3 & 4			NG-Fugitives Increase		SF_6 Fug Increase	Fuel Gas Heaters 2A, 3 & 4		Emergency Generators 2,3 & 4		TOTAL
	Normal, lb/hr	SSM, lb/hr	Total, tons/yr	lb/hr	tons/yr	tons/yr	lb/hr	tons/yr	lb/hr	tons/yr	tons/yr
CO_2	698,248	698,248	1,596,020	0.032	0.14		1941.18	4,437	7,673	383.67	1,600,841
CH_4	36	535	375	1.58	6.92		0.037	0.085	0.45	0.030	381.95
N_2O	17	17	40				0.036	0.082			39.98
SF_6						0.0037					0.0037
GHG	698,302	698,800	1,596,435	1.61	7.06	0.0037	1941.25	4,437	7,674	383.70	1,601,263
CO_2-e	704,352	714,927	1,617,282	39.53	173.14	83.22	1952.75	4,463	7,686	384.00	1,622,386

Bases for Calculations

- Total Annual Operating Hours, Normal Maximum Operation	4000
- Total Number of 30-min Startups Per Year	635
- Maximum Duration of Startup (to 50% load), min	30
- Maximum Annual Startup Hours	317.5
- Total Number of Shutdowns Per Year	635
- Maximum Duration of Shutdown (from 50% load), min	24
- Normal Operating Hours, % of Total	87.5%
- Startup, Shutdown, or Maintenance (SSM) Hours, % of Total	12.5%
- Maximum Annual Shutdown Hours	254
- Basis of Turbine Emission Rates	Vendor data except as noted
- Maximum Turbine Firing Duty, MM Btu/hr (HHV)	1941

Maximum Emission Rates

	Turbine 2, 3, or 4					
	Normal, lb/hr	Startup, lbs/start-up	Startup, lbs/hr (incl. normal operation)	Shutdown, lbs/shutdown	Shutdown, lbs/hr (incl. normal operation)	Annual, tons/yr
CO_2	232,749	N/A	232,749	N/A	232,749	532,007
CH_4	12	147	153	171	178.2	124.97
N_2O	5.82	N/A	5.82	N/A	5.82	13.3
CO_2-e	234,784	N/A	238,309	N/A	238,939	539,094

Example Calculation of Annual Emissions

Annual CH_4 Emissions from Turbine 2, 3, or 4:

[(4000 hours X 12 lb/hr) + (635 startups X 147 lbs/startup) + (635 shutdowns X 171 lbs/shutdown)] X (1 ton / 2000 lbs) = 124.97 tons/yr

Tabulation of HAPs and N_2O Emission Factors from AP-42, Tables 3.1-2a and 3.1-3

HAPs (Total)	0.00103	lbs/MM Btu
N_2O	0.003	lbs/MM Btu

Tabulation of GHG Warming Potential Equivalency Factors (40 CFR Part 98 Subpart A, Table A-1)

CO_2	1	kg CO_2-e/kg CO_2
CH_4	25	kg CO_2-e/kg CH_4
N_2O	298	kg CO_2-e/kg N_2O

Calculation of Normal CO_2-e Hourly Emissions

(232,749 lb CO2/hr) X (1lb CO2-e/lb CO2) + (12 lbs CH4/hr) X (25 lb CO2-e/lb CH4) + (5.82 lbs N2O/hr) X (298 lb CO2-e/lb N2O) =
234,784 lbs CO_2-e/hr

Note: AP-42 is the U.S. EPA's *Compilation of Air Pollutant Emission Factors*, 5th Edition.

Emission Bases and Calculations

Total Emissions for Elk Units 1-4

Emission Source Characteristics	
- No. of Gas Valves:	400
- No. of Gas Flanges:	400
- No. of Gas Relief Valves:	24
- No. of Sampling Connections:	24
Emission Factor, scf/hr/component	
- Gas Valve:	0.123
- Gas Flange:	0.017
- Gas Relief Valve:	0.196
- Gas Sampling Connection*:	0.123
*Used factor for gas valves since no factor is provided in Table W-1A of 40 CFR 98.	
Source of Emission Factors:	Table W-1A of 40 CFR 98
Annual Hours of Operation:	8760
Maximum Component Compositon, % Vol	
- CH_4:	93.1548
- CO_2:	0.6728
Molecular Weights	
- CH_4:	16.04
- CO_2:	44.01
Calculated Fugitive Release, scf/hr = ∑ (no. of components) X (emission factor, scf/hr/component) = 63.656 scf/hr	
GHG Equivalency Factors, lb CO_2-e/lb:	
- CH_4:	25
- CO_2:	1

	Calculated Emission Rates		Currently Permitted		Emission Rate Increases	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
CH_4	2.51	10.99	0.93	4.07	1.58	6.92
CO_2	0.050	0.219	0.018	0.079	0.032	0.14
CO_2-e	62.8	274.97	23.268	101.83	39.532	173.14

Example Calculation of Hourly Emissions (CH_4):

(63.656 scf/hr) * (93.1548 scf CH4/100 scf gas) X (1-lb-mol/379 scf) X (16.04 lbs CH4/lb-mol) =
2.51 lbs CH_4/hr

Example Calculation of Annual Emissions (CH4)

(2.51 lbs/hr) X (8760 hrs/yr) X (1 ton/2000 lbs) = 10.99 tons CH_4/yr

Example Calculation of CO_2-e Hourly Emissions

(0.050 lb CO2/hr) X (1lb CO2-e/lb CO2) + (2.51 lbs CH4/hr) X (25 lb CO2-e/lb CH4) =
62.80 lbs CO_2-e/hr

Emission Bases and Calculations

Total Emissions from Elk Units 1-4

No. of Circuit Breakers:	12
Amount of SF_6 in each Circuit Breaker, lbs:	365
Estimated annual leak rate, wt. %:	0.5
Estimated annual SF6 emissions = (12 breakers) X (365 lbs/breaker) X (0.5 % lost/yr) X (1 ton/2000 lbs) =	
0.01095 tons SF_6/yr	
GHG Equivalency Factor, ton CO_2-e/ton SF_6:	22800
Estimated annual CO_2-e emissions = (0.01095 tons SF6/yr) X (22800 tons CO2-e/ton SF6) =	
249.66 tons CO_2-e/yr	

Current Permit	
0.0073	tons SF_6/yr
166.44	tons CO_2-e/yr
Proposed Increase	
0.00365	tons SF_6/yr
83.22	tons CO_2-e/yr

Diesel-Fired Generator - Cummins QSK50-G4 NR2 or equivalent

Maximum Gross Generator Output , kW	1656
Maximum Fuel Consumption, gal/hr	109.4
Maximum Fuel Consumption (calculated), MM Btu/hr[1]	15.316
Maximum Brake Horsepower, bhp	2205
Annual Hours of Non-Emergency Operation	100
Number of New Generators	3

GHG Pollutants [2]

	CH_4	CO_2	CO_2-e
Emission Factor, g/bhp-hr	0.03	526.18	N/A
Hourly emissions for 1 generator, lbs/hr	0.15	2557.8	2562
Annual emissions for 1 generator, tons/yr	0.01	127.89	128
Hourly emissions for 3 generators, lbs/hr	0.45	7673.40	7686
Annual emissions for 3 generators, tons/yr	0.03	383.67	384

Tabulation of GHG Warming Potential Equivalency Factors (40 CFR Part 98 Subpart A, Table A-1)

CO_2	1 kg CO_2-e/kg CO_2
CH_4	25 kg CO_2-e/kg CH_4

Example Calculation of CO_2-e Hourly Emissions

(2,558 lb CO2/hr) X (1lb CO2-e/lb CO2) + (0.15 lbs CH4/hr) X (25 lb CO2-e/lb CH4) = 2,562 lbs CO_2-e/hr

Example Calculation of CO_2 Hourly Emissions

Vendor Data: (2205 bhp) X (526.176 g CO2/bhp-hr) X (1 lb/453.6 g) = 2557.8 lbs CO_2/hr

Example Calculation of CO_2 Annual Emissions

(2557.8 lbs CO2/hr) X (100 hours/yr) X (1 ton/2000 lbs) = 127.89 tons CO_2/yr

[1] Based on 140,000 BTU (HHV)/gal.

[2] Based on Vendor Emission Data Sheet.

Heater Bases

Heat Content of Fuel:	1,020 Btu/scf
Total Heater Fuel Firing Capacity:	5.5 MM Btu/hr
Total Heater Gas Capacity:	5,392 scfh
Maximum Operating Hours per year:	4,572
Maximum Annual Burner Gas Capacity:	24.65 MM scf/yr
Number of New Units:	3

Emission Factors and Emission Calculations for Gas Combustion Pollutants

Constituent	Emission Factor (lb/MM scf)	Source of Emission Factor	Emissions, lb/hr	Emissions, ton/yr	Emissions, lb/hr (3 units)	Emissions, ton/yr (3 units)
CO_2	1.20E+05	AP-42, Table 1.4-2	647.1	1479.0	1941.2	4437.0
CH_4	2.30	AP-42, Table 1.4-2	1.24E-02	2.83E-02	0.037	0.085
N_2O	2.2	AP-42, Table 1.4-2	0.0119	2.72E-02	0.036	0.082
GHG	N/A	N/A	647.1	1479.1	1941.2	4437.2
CO_2-e	N/A	N/A	650.9	1487.8	1952.7	4463.5

Basis for Calculations:
Emissions (lb/hr) = [Emission Factor (lb/MM scf)] X [Fuel Usage (scf/hr)] X [MM scf/1000000 scf]
Emissions (ton/yr) = [Hourly Emissions (lb/hr)] X [Maximum Annual Operating Hours (hours/yr)] X [1 ton/2000 lb]
Emissions (lb/yr) = [Hourly Emissions (lb/hr)] X [Maximum Annual Operating Hours (hours/yr)]
Emission factors are from the EPA's ***Compilation of Air Pollutant Emission Factors*** , 5th Edition, "Section 1.4, Natural Gas Combustion", for uncontrolled small boilers.

5.0 PSD APPLICABILITY SUMMARY

As shown in Tables 1 and 1F, the proposed gas turbines and associated facilities will increase emissions at Antelope Elk Energy Center by 1,601,263 tons/yr of GHG pollutants and 1,622,386 tons/yr of CO_2-e. Under the U.S. Environmental Protection Agency's (EPA's) Prevention of Significant Deterioration (PSD) regulations in 40 CFR 52.21, Antelope Elk Energy Center is currently a major source of both GHG and "criteria" (non-GHG) pollutants. Under the current PSD rules and guidance, the project to install three gas turbines and associated equipment at Antelope Elk Energy Center is required to obtain authorization for its GHG emissions from the EPA. (A State Implementation Plan to enable Texas to directly review and process GHG permit applications is pending.) The proposed project is also subject to PSD review by the Texas Commission on Environmental Quality (TCEQ) for non-GHG emissions, since it will release carbon monoxide (CO), nitrogen oxides (NOx), particulate matter less than 10 microns in diameter and less than 2.5 microns in diameter at rates above their PSD significant emission rates. These non-GHG emissions, and other pollutants with emission rates below the respective PSD significant emission rates, are subject to the State of Texas pre-construction authorization requirements, and authorizations for those associated facilities and emissions will be obtained separately from the TCEQ.

Sources and emissions subject to PSD permitting requirements because of their potential to release GHG emissions are subject only to some of the requirements of the PSD rules. The primary requirement of a PSD permit for GHG emissions is to require that the permitted facilities use the Best Available Control Technology (BACT) for controlling GHG emissions. The resulting PSD permit specifies emission levels reflecting the use of BACT, including emissions monitoring and other requirements to ensure that the BACT emission levels are maintained during operations. An analysis of and rationale for BACT for the GHG emissions from the new gas turbine facility at Antelope Elk Energy Center are provided in Section 6.0.

GHG emissions from the proposed gas turbine facility are not subject to other PSD permit requirements. The facility is not subject to an analysis of ambient air impacts because there are no National Ambient Air Quality Standards or PSD Ambient Air Increments for GHG emissions. It is not subject to preconstruction ambient air monitoring because of the nature of GHG emissions and their potential global impact; there is no benefit for the gathering of local ambient air monitoring data on GHG pollutants. EPA's permitting guidance for GHG also indicates there is no need to conduct analyses of additional impacts on Class I areas, soils and vegetation because quantifying the impacts attributable to a single source is not feasible with current climate change models.[3]

[3] U.S. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, EPA-457/B-11-001, March 2011.

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: **109148 / PSDTX1358**	Application Submittal Date: **July 2014**
Company: **Golden Spread Electric Cooperative, Inc.**	
RN: **RN105862510**	Facility Location: **Plant site is north of County Road 315, east of I-27, and bounded on the east by County Road P, about 1.6 miles north of the City of Abernathy, Texas**
City: **Abernathy**	County: **Hale**
Permit Unit I.D.: **Antelope Elk Energy Center**	Permit Name: **Turbines 2, 3, and 4**
Permit Activity: ☐ New Source ☒ Modification	

Complete for all Pollutants with a Project Emission Increase.	**POLLUTANTS**							
	Ozone							
	VOC	**NO_x**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**NO_X**	**SO_2**	**CO_2-e**
Existing Site Nonattainment Permit?	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**
Existing Site PSD Permit?	**No**	**Yes**	**Yes**	**No**	**No**	**Yes**	**No**	**Yes**
Existing site PTE (tpy)?	248.48	261.64	496.18	146.15	146.15	173.11	48.45	728,408
Proposed project emission increases[1]?	95.69	427.57	785.64	64.20	64.20	427.57	37.45	1,622,~~552~~ 386
Is the existing site a major source?	**No**	**Yes**	**Yes**	**No**	**No**	**Yes**	**No**	**Yes**
If not, is the project a major source by itself?	**No**	**Yes**	**Yes**	**No**	**No**	**Yes**	**No**	**Yes**
If site is major source, is project increase significant?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**
If netting required, estimated start of construction: **N/A since major "existing" unit has just started construction and other existing units are un-modified.**								
5 years prior to start of construction **N/A**								contemporaneous
Estimated start of operation **N/A**								period
Net contemporaneous change, including proposed project (tpy)	95.69	427.57	785.64	64.20	64.20	427.57	37.45	1,622,~~552~~ 386
Major NSR Applicable?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**

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

[signature]	Vice President, Production	7-9-14
Signature	*Title*	*Date*

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

TCEQ - 10154 (Revised 04/12) Table 1F
These forms are for use by facilities subject to air quality permit requirements and may be revised periodically. (APDG 5912v2)

6.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

EPA's PSD rules require that any emissions emitted above the significant increase level, and thus subject to the PSD permitting process, be subject to the BACT analysis. Title 40 CFR 52.21(b)(12) reads in part:

> *Best available control technology* means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [this] 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.

BACT is established in a top-down analysis where the most effective control technology is selected if it is technically feasible and has "reasonable" energy, environmental, and economic/cost impacts. As described in EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (EPA, 2011) the steps to be followed in establishing BACT are the following:

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

These steps are used below to evaluate and select BACT for the proposed turbine facility at Antelope Elk Energy Center.

6.1 Gas Turbines

6.1.1 Step 1 - Identify all available control technologies.

There are four fundamental control technology options for the gas turbines. The first is carbon capture and storage (CCS). CCS is an add-on technology that captures GHG emissions resulting from natural gas combustion before they enter the atmosphere. In this instance the captured CO_2 would be compressed and transported via pipeline to a site where the CO_2 could either be stored or used (for example, for enhanced oil recovery). The second option is the use of combined cycle technology instead of simple cycle turbines. The third option is use of a fuel with lower GHG emissions per unit of energy. The fourth option is the baseline option of using an efficient gas turbine technology and maintaining and operating each turbine train component properly.

6.1.2 Step 2 - Eliminate technically infeasible options.

According to EPA GHG Permitting Guidance document a technology is technically feasible if it (1) has been demonstrated and operated successfully on the same type of source under review or, (2) is available and applicable to the type of source under review.[4]

[4] Ibid, page 33.

Carbon Capture and Storage

In the United States, there are presently no existing demonstrations of CCS systems used in the removal of CO_2 from natural-gas turbines, from turbines fired with other fuels, or from gas-fired, liquid-fired, or solid-fired boilers and furnaces.[5] One project, the Kemper County Integrated Gasification Combined Cycle Project, is under construction in Mississippi.[6] This project features the removal of CO_2 from a syngas produced from coal gasification; the syngas is then used in a conventional combined cycle power unit. A similar demonstration project, the Texas Clean Energy IGC project, has been planned for Penwell, Texas but construction has not begun.[7] Both of these projects will use technology in a pre-combustion application similar to gas processing conducted in petroleum refineries and natural gas treatment facilities, and do not demonstrate CCS on post-combustion equipment exhausts. Combustion exhausts are at low pressure while gasifier streams are at medium to high pressure: the low pressure in turbine exhausts limits the availability, viability, and practicability of technologies for the removal of CO_2 since some technologies are viable only at medium or high pressure. In addition, the concentration of CO_2 in combustion exhausts is much lower than in gasifier streams. Overall, the lack of utilization of the CO_2 capture/compression/transport/storage as BACT reflects the emerging nature of the CCS technology and the fact that it is not deployed even in demonstration projects on combustion sources.

Just two years ago, the President's Interagency Task Force on Carbon Capture and Storage 2010 report found,

> Current technologies …are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment.[8]

CCS systems comprise three key systems: capture, transport and storage.

Capture

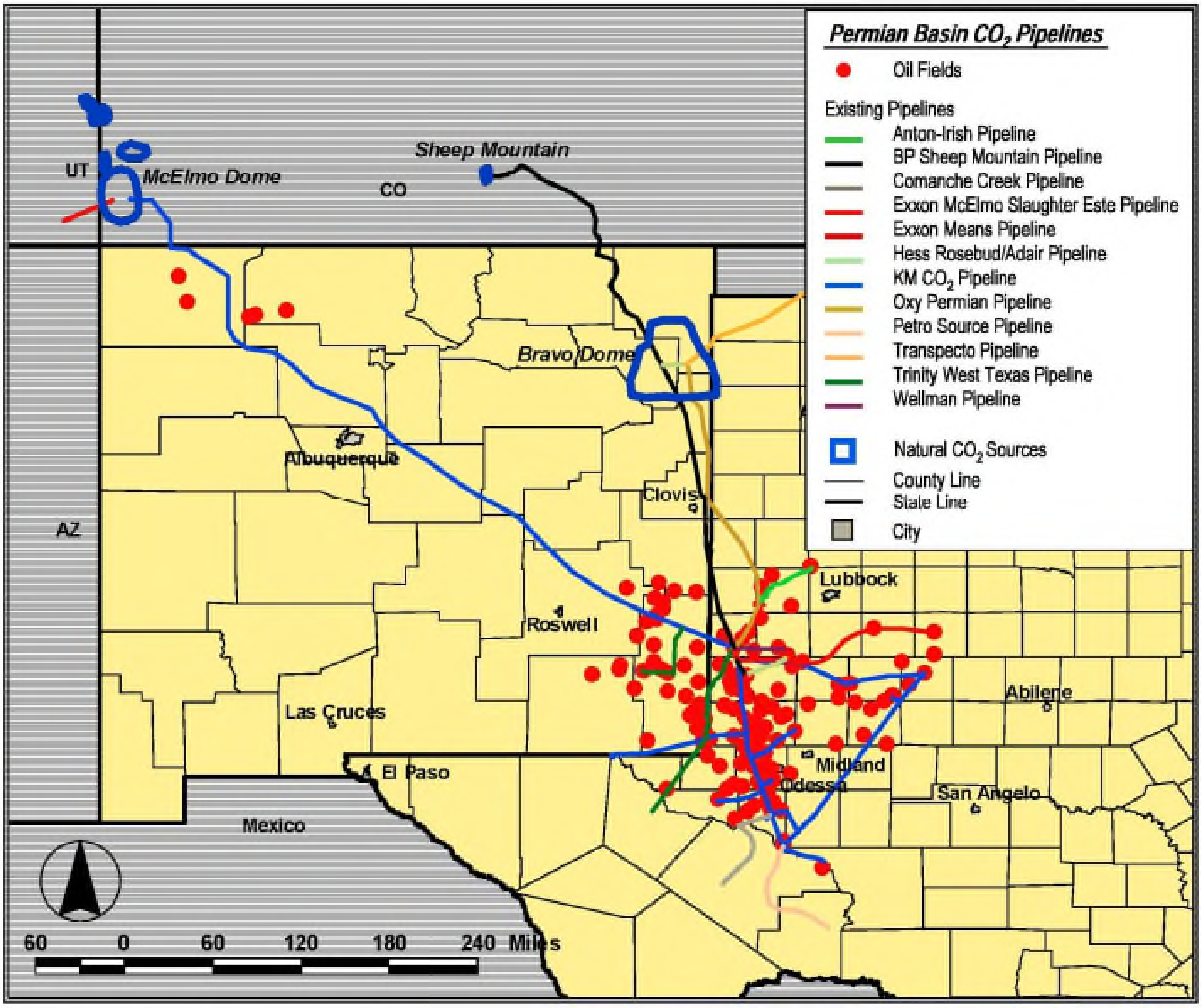
The CO_2 capture system uses one of several absorption processes to absorb CO_2 from the combustion exhaust gas into a liquid such as monoethanolamine. The absorbed CO_2 is then released by changing the temperature and/or pressure of the absorbing liquid. The enriched CO_2 stream must then be compressed for transport to storage or an end-use. The absorption and compression processes increase the internal energy use for the power plant by 10-40%.[9]

Transport

[5] Search of EPA's RACT/BACT/LAER Clearinghouse, EPA Clean Air Technology Center, 10/8/2012, and literature survey.
[6] Whether Mississippi Power can recover the costs of building the Kemper facility is currently pending before the Sixth Chancery Court District of Mississippi.
[7] According to the Penwell project website, as of September 14, 2012 construction of this project had not begun. http://www.texascleanenergyproject.com/news-room/
[8] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010.
[9] Intergovernmental Panel on Climate Change, Special Report on Carbon Dioxide Capture and Storage, (Bert Metz et al. eds., 2005)

The availability of transportation to move the captured CO_2 presents a second critical issue to the technical viability of the CCS option.

CO_2 pipelines in the Permian Basin are shown in the figure below. There are presently no existing pipelines that could transport the CO_2 stream from Antelope Elk Energy Center to a storage facility or an enhanced oil recovery ("EOR") field. The closest existing CO_2 pipeline – the Anton-Irish Pipeline - is located



CO_2 Pipelines in the Permian Basin[10]

about twenty miles west of Antelope Elk Energy Center. The Anton-Irish Pipeline is an 8" pipeline that is privately owned by Oxy Permian and the line's capacity is dedicated to Oxy's operations.[11] Because this is a private line, GSEC cannot demand access to the line and even if Oxy were amenable to GSEC using its line, whether the pipeline or the site it delivers to have any available capacity is unknown to GSEC. In addition the Anton-Irish line may not be suitable for the transportation of anthropogenic CO_2. In its 2012 report The Global CCS Institute noted:

[10] Advanced Resources International, *Basin-Oriented Strategies for CO2 EOR: Permian Basin*, prepared for U.S. Department of Energy, February 2006.
[11] A Policy, Legal and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide, page 38 (September 2010).

> [T]here are significant differences between the US experience with CO_2 EOR pipelines (mainly dealing with naturally occurring CO_2), and the expertise needed to design transport systems for anthropogenic CO_2. The composition of CO_2 that is captured from power plants, for instance, will influence the hydraulics calculations that are needed to design these pipelines. Impurities or by-products such as nitrogen, argon, methane, and hydrogen lower the density of a CO_2 stream, resulting in a higher pressure drop…Moreover, combinations of impurities (e.g. from different sources) could together raise the critical pressure more than that from one component in isolation. The characteristics of CO_2 with impurities are therefore vitally important to know in order to properly engineer a CO_2 transport system. Detailed thermodynamics of CO_2 with impurities has been modeled, but the available models need to be **further** validated.[12]

Aside from the costs related to the building of a new CO_2 line, there are other adverse factors. Private right of way would need to be obtained from likely hundreds of landowners. The sensitivity of and impact on wildlife of such a pipeline would need to considered along with the time delays inherent in obtaining all of the required permits and approvals from State and possibly Federal agencies.

Storage

Finally, the availability of a geologic storage site for the storage of the captured CO2 or for use in EOR operations presents many technical challenges. After a search of publicly available information, GSEC was unable to find any geologic sites in the immediate vicinity of Antelope Elk Energy Center that are viable for large-scale, long-term CO_2 storage. Even if there were a storage site with available capacity, any geologic site to be used for CO_2 injection and storage would need to be extensively characterized and studied which would take several years and would cost several million dollars.[13] The viability of a potential storage site depends on the trapping mechanisms and capacity of the geological formations, and the risks for environmental effects on subsurface and surface waters resulting from pipeline and storage facility leaks. In addition the quality of the CO_2 produced from the Antelope Elk Energy Center would impact the suite of storage options available to it. While EOR sites exist in the Permian Basin, Antelope Elk Energy Center is approximately 20 miles away from the nearest possible pipeline terminus and the transportation challenges noted above would apply. In addition, whether the captured CO_2 would be suitable for injection as part of an EOR operation is unknown.

Because of the lack of demonstration of CCS on gas turbine power plants, and other power plant applications, lack of commercial deployment, lack of a transport pipeline, and uncertainties on the possible use of the CO_2 for EOR or for storage in geologic storage sites, CCS is not considered to be a technically viable option.

Combined Cycle Technology

The EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases," indicates that the use of combined cycle turbine technology could be considered as "redefining-the-source" and excluded from consideration at Step 1 on a case-by-case basis if it can be shown that application of this control technology would disrupt the basic business purpose for the proposed facility. GSEC's project provides peaking and intermediate power quickly when dispatched to respond to varying needs of the electric grids GSEC supports, including support of renewable power generation by maintaining grid stability when wind power generation decreases, and to expeditiously shut down when no longer needed.

[12] Global CCS Institute, The Global Status of CCS: 2012, Canberra Australia, 123-124 (emphasis added).
[12] Ibid. at 129.

Simple cycle turbines, such as those proposed, are well suited for peaking power supply due to their ability to rapidly respond to immediate needs for additional power generation at variable levels and quickly cease operation when those additional power needs are satisfied. Simple cycle turbines are also well suited for this smaller peaking and intermediate facility (100-200 MW) by providing the flexibility to operate at partial load and respond to dispatch requirements in smaller increments than would be practicable with the operation of a larger combined cycle plants.

Combined cycle units generally have higher efficiencies than simple cycle units; however, while combined cycle units are well suited as baseload power generating units, combined cycle units cannot provide the rapid response and shutdown required of a peaking power source producing power to sell in a deregulated market or responding to fluctuations in renewable power generation. The start-up sequence for a combined cycle plant includes three phases: 1) purging of the heat recovery steam generator (HRSG); 2) gas turbine speed-up, synchronization and loading; and 3) steam turbine speed-up, synchronization and loading. The duration of the third phase of this process is dependent on the amount of time that the plant has been shut down prior to being restarted, because the HRSG and steam turbine contain parts that can be damaged by thermal stress and require time to heat up and prepare for normal operation. For this reason, the complete startup time for a combined cycle plant is typically longer than that of a similarly sized simple cycle plant. In meeting GSEC's fundamental needs, the combustion turbine needs to be able to start up quickly, cycle off when not required, and accommodate the rapidly changing scale and complexity of providing power generation support for renewable energy sources.

Fast-start technology is capable of enabling startup of a combined cycle combustion turbine within 30 minutes; however, the technology requires that the unit be maintained in a state allowing warm or hot startup. To keep the HRSG and the steam turbine seals and auxiliary equipment at a sufficiently high temperature to allow for quick startup of the combustion turbine, the facility would have to continuously operate an auxiliary boiler. These longer startup times are incompatible with the purpose of the proposed project to provide a rapid response to changes in the supply of renewable power and demand for electricity.

An additional concern with the use of a combined-cycle configuration is the thermal mechanical fatigue due to the large numbers of startups and shutdowns. There are many considerations in the successful selection of a steam turbine design that include correct steam chemistry, establishment of steam seals, vibration, and controls. For fast-start technology, one of the most important factors is the thermal stress management. For a high pressure drum type HRSG, thermal stress management becomes an integral part of the design considerations. For fast-start technology to optimize the startup to minimize the time to dispatch power without a system failure, the gas turbine and steam turbine must be thermally decoupled. The steam turbine metal temperature at the startup initiation is a key controlling factor to establishing startup times. To help alleviate, to a certain degree, the impacts from thermal stress, a stronger alloy steel (resulting is a higher cost) may need to be used in the steam turbine.

If combined cycle turbines were incorporated into combined cycle units, the minimum electricity generation output would be substantially higher than the 100 MW minimum output of a simple cycle configuration. GSEC's business purpose requires the ability to accommodate flexible and on-demand operations in the 100 MW to 202 MW range, including the operational flexibility to start up and shut down to respond immediately to variable electricity grid demand in support of renewable power sources within GSEC's power generation portfolio and as dispatched by ERCOT and SPP.

Based on the defined business purpose of the proposed project and for the reasons discussed above, the use of combined cycle units would result in a redefinition of the source for this specific project and can be excluded from Step 1 of this BACT analysis.

Use of Fuel with Lower GHG Emissions

The use of natural gas fuel is technically viable.

Use of Efficient Turbine Technology and Operating and Maintaining the Unit Efficiently

Gas turbo machinery such as that proposed for use at Antelope Elk Energy Center are readily commercially available and demonstrated in practice, and are considered to be technically viable. The new turbines proposed for Antelope Elk Energy Center have low heat rate (conversely, a high energy efficiency) due to the use of advanced gas turbine technology. By minimizing fuel usage, these techniques also minimize the release of GHG.

6.1.3 Step 3 - Rank remaining control technologies.

The BACT options proposed by GSEC comprise both of the technically viable options: 1) use of natural gas fuel, and 2) use of efficient gas turbine technology.

6.1.4 Step 4 - Evaluate the most effective controls and document results.

The base case options of the use of natural gas fuel and advanced F class turbines entail no adverse economic or energy impacts.

6.1.5 Step 5 - Select the BACT.

Technical feasibility and demonstration, economic, energy, and environmental impact factors all support the base case options as BACT. BACT for GHG emissions is the use natural gas fuel combined with the efficient gas turbine technology proposed for the Antelope Elk Energy Center, with the turbines operated and maintained properly according to the manufacturer recommendations.

6.2 Natural Gas Line Fugitives

Increased fugitive emissions from the natural gas supply lines due to the proposed project amount to 173.14 tons/yr of CO_2-e emissions, and 7.06 tons/yr of GHG emissions on a mass basis.

6.2.1 Identify all available control technologies.

Piping fugitive leaks can be controlled by three basic approaches:

1) Use of leak-less and/or seal-less equipment,
2) Use of a leak detection and repair program using either periodic leak inspection by instrument or remote sensing of leaks by infrared camera,
3) Use of audio/visual/olfactory (AVO) observations of leaks in periodic walkthroughs as part of normal operations. (This method of control results in the base emissions of fugitive leaks.)

6.2.2 Eliminate technically infeasible options.

Leak-less piping equipment has been used in the chemical process industry when toxic or hazardous materials are used. They have not been used in natural gas supply lines, and operating/maintenance problems with their operation would require line shutdowns to effect repairs. Because of the safety risk and increased GHG emissions of line shutdowns to repair leak-less equipment, and because the natural gas fuel lines do not contain toxic or hazardous materials, the use of leak-less piping components is infeasible and impracticable. The other options to control fugitive leaks are technically feasible.

6.2.3 Rank remaining control technologies.

Both instrument detection of leaks and remote sensing of leaks have been determined to be equivalent control methods by EPA.[14] These methods are ranked as most effective, with an estimated effectiveness of 75-95%. AVO methods are less effective since their observations are not conducted at specified intervals. However, because of the presence of natural gas odorants and the high pressure of the natural gas, AVO is moderately effective. We have not attributed a control efficiency to the AVO monitoring by periodic walk-around inspections because this technique is very likely included with the emission factor used to estimate GHG emissions.

6.2.4 Evaluate the most effective controls and document results.

Leak monitoring quarterly using instrument monitoring or remote sensing would provide an overall reduction of 85% of the CO_2-e emissions from equipment leaks, at a cost effectiveness of $150-290/ton CO_2-e reduced. Periodic AVO monitoring, as a base option, would have no costs other than those included in normal plant operation and maintenance expense. None of these options have significant adverse environmental or energy impacts.

6.2.5 Select the BACT.

Due to the high cost of instrument monitoring or remote monitoring of leaks, with a cost effectiveness of $150-290/ton CO_2-e, neither of these options are BACT for fugitive leaks from the natural gas supply system. BACT is the periodic AVO observation of piping equipment.

6.3 SF_6 Leaks from Circuit Breakers

Increased SF_6 leaks from circuit breakers will amount to 83.22 tons/yr of CO_2-e emissions, and 0.00365 tons/yr of GHG emissions on a mass basis.

6.3.1 Identify all available control technologies.

There are two technology options. The first is to replace SF_6 with an alternate dielectric material or alternative type of circuit breaker. The second is to use comprehensive leak detection with modern SF_6 circuit breaker technology.

6.3.2 Eliminate technically infeasible options.

Although the development of alternative dielectric materials and types of circuit breakers is underway, no alternative or option has been found to be superior to SF_6 based circuit breakers for high voltage applications. SF_6 provides better electrical insulation, and quenches electric arcs more effectively. Circuit-breakers using SF_6 as the insulating and quenching medium are smaller, safer, and have longer useable lifetimes than alternatives. As such, the use of alternate dielectric materials or types of circuit breaker is not technically feasible.

[14] 73 FR 78199-78219, December 22, 2008.

The use of leak detection and modern SF_6 circuit breaker technology is feasible.

6.3.3 Rank remaining control technologies.

The use of modern circuit breaker technology and comprehensive leak detection methods will allow Antelope Elk Energy Center to achieve a leak rate of 0.5%/year.

6.3.4 Evaluate the most effective controls and document results.

The use of modern circuit breaker technology and comprehensive leak detection methods will not cause any significant adverse economic, environmental, or energy effects.

6.3.5 Select the BACT.

Use of modern circuit breaker technology and a comprehensive leak detection and disposition program constitutes BACT. The comprehensive program will involve inventory and use tracking, leak detection by hand-held halogen detectors, and low-gas density alarms. It will also include a recycling program so that SF_6 is evacuated into portable cylinders rather than vented to atmosphere.

6.4 Backup/Emergency Generators

The diesel fired emergency generators will each normally operate less than 100 hours per year in non-emergency operations. GHG from the three proposed emergency generators will amount to 384 tons/yr of CO_2-e emissions, and 383.7 tons/yr of GHG emissions on a mass basis.

6.4.1 Identify all available control technologies.

There are two options for control of GHG emissions from the emergency generators. The first is to implement an add-on CCS option. The second is to use a modern efficient generator technology and to maintain and operate the emergency generator properly, according to manufacturer recommendations and good combustion practice.

6.4.2 Eliminate technically infeasible options.

The use of CCS is not technically feasible for the emergency generator due to the generator's infrequent but critical operating requirements for quick response, short-duration operation; the operating period for the generator would usually end before the CCS absorption unit has reached normal operation. Except for its periodic testing, the emergency generator is intended to operate only for situations when grid power may not be available, when its entire electrical output is required for the situation. No CCS systems have been demonstrated for use on emergency generators.

Use of modern generator technology, and maintaining and operating the generators properly is technically viable, as demonstrated by widespread use of these units.

6.4.3 Rank remaining control technologies.

The only option is the base option to use modern generator technology, and to maintain and operate the generators properly, according to manufacturer recommendations and good combustion practice.

6.4.4 Evaluate the most effective controls and document the results.

GHG emission estimates for the emergency generators reflect the base option of the use of modern generator technology and to maintain and operate the generators properly. There are no cost impacts for this option. Energy usage for the generators is comparable to that of a simple cycle gas turbine. There are no adverse environmental effects from the limited operation of the generators.

6.4.5 Select the BACT.

BACT is to use modern generator technology, and to maintain and operate the generator properly according to manufacturer recommendations, and to operate at the minimal schedule proposed in the permit application.

6.5 Natural Gas Heaters

GHG from the proposed three natural gas heaters will amount to 4463 tons/yr of CO_2-e emissions, and 4437 tons/yr of GHG emissions on a mass basis.

6.5.1 Identify all available control technologies.

There are three options for control of GHG emissions from the natural gas heaters. The first is to implement the add-on CCS option. The second is to use an alternate design to the indirect-fired water bath heater. The third is to maintain and operate the heaters properly, according to manufacturer recommendations and good combustion practice.

6.5.2 Eliminate technically infeasible options.

The use of CCS is not technically feasible for the natural gas heater due to the small size of the combustion unit. No CCS systems have been demonstrated for use on heaters of this size nor on heaters of this configuration.

Due to process safety considerations, and due to the low heat demand needed to increase the temperature of the turbine natural gas fuel above the dewpoint, heaters in this type of application are nearly always of the indirect-fired water bath configuration. This type of heater achieves an energy transfer efficiency of 70-80%. Higher efficiency direct-fired heaters are not considered to be technically feasible due to process safety issues, and to control issues which can lead to overheating the natural gas stream.

Maintaining and operating the heater properly is technically viable, as demonstrated by widespread use of these units.

6.5.3 Rank remaining control technologies.

The only option is the base option to maintain and operate the heater properly, according to manufacturer recommendations and good combustion practice.

6.5.4 Evaluate the most effective controls and document the results.

GHG emission estimates for the natural gas heaters reflect the base option to maintain and operate the heater properly. There are no cost impacts for this option. Energy impacts are comparable to other heaters of this type. There are no adverse environmental effects from the operation of the heaters.

6.5.5 Select the BACT.

BACT is to maintain and operate the heaters properly according to manufacturer recommendations.

6.6 Proposed Emission and Production Limits, Monitoring, and Maintenance Requirements

Table 7 shows the emission and production limits, monitoring, and maintenance requirements proposed to support BACT.

Emission Source	Emission and Production Limits	Monitoring Requirements	Maintenance Requirements
Gas turbines (3)	• 532,700 tons/yr CO_2 (each turbine) • 232,749 lbs/h CO_2 (each turbine) • 1217 lbs CO_2/MWh (gross) @ max. load • 1558 lbs CO_2/MWh (gross) @ at 50% load (max. limit for any load)	• Determine hourly and annual GHG emissions using 40 CFR 98.43 • Determine and record CO_2 emissions on a rolling 4572 operating hours basis • Record gross electricity output in MWh on a rolling 4572 operating hours basis • Determine and record lbs CO_2/MWh (gross) as a rolling 4572 operating hours basis	• Operate and maintain all equipment according to manufacturer recommendations
Natural Gas Piping Fugitive Leaks (Total)	• 275 tons/yr CO_2-e (total)	• Record leak observations reporting by operating and maintenance staff	• Operate and maintain all equipment according to manufacturer recommendations
SF_6 Fugitive Leaks (Total)	• 250 tons/yr CO_2-e (total)	• Use inventory records to determine SF_6 and CO_2-e emissions on a calendar year basis • Monitor for leaks using halogen detector on a monthly basis	• Implement a recycling program so that SF_6 is evacuated into portable cylinders rather than vented to atmosphere. • Operate and maintain all equipment according to manufacturer recommendations
Emergency Generators (3)	• 128 tons/yr CO_2-e (each generator)	• Determine annual CO_2-e emissions using 40 CFR 98.33 on a calendar year basis	• Operate and maintain all equipment according to manufacturer recommendations
Natural Gas Heaters (3)	• 1488 tons/yr CO_2-e (each heater)	• Determine annual CO_2-e emissions using 40 CFR 98.33 on a calendar year basis	• Operate and maintain all equipment according to manufacturer recommendations

Table 7. Proposed Emission and Production Limits, Monitoring, and Maintenance Requirements