PREVENTION OF SIGNIFICANT DETERIORATION PERMIT FOR GREENHOUSE GAS EMISSIONS ISSUED PURSUANT TO THE REQUIREMENTS AT 40 CFR § 52.21

U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION 6

PSD PERMIT NUMBER:	PSD-TX-1298-GHG
PERMITTEE:	Pinecrest Energy Center, LLC 3608 Preston Road, Suite 225 Plano, TX 75093
FACILITY NAME:	Pinecrest Energy Center, LLC Pinecrest Energy Center (PEC)
FACILITY LOCATION:	1002 East Park Avenue Lufkin, TX 75904

Pursuant to the provisions of the Clean Air Act (CAA), Subchapter I, Part C (42 U.S.C. § 7470, *et seq.*), and the Code of Federal Regulations (CFR) Title 40, Section 52.21, and the Federal Implementation Plan at 40 CFR § 52.2305 (effective May 1, 2011 and published at 76 FR 25178), the U.S. Environmental Protection Agency, Region 6 is issuing a *Prevention of Significant Deterioration* (PSD) permit to Pinecrest Energy Center, LLC (Pinecrest) for greenhouse gas (GHG) emissions. The permit applies to the construction of a new natural gas fired combined cycle electric generating plant, Pinecrest Energy Center (PEC), to be located near Lufkin, Angelina County, Texas.

Pinecrest is authorized to construct a new natural gas fired combined cycle electric generating plant as described herein, in accordance with the permit application (and plans submitted with the permit application), the federal PSD regulations at 40 CFR § 52.21, and other terms and conditions set forth in this PSD permit in conjunction with the corresponding Texas Commission on Environmental Quality (TCEQ) PSD permit No. PSD-TX-1298. Failure to comply with any condition or term set forth in this PSD permit may result in enforcement action pursuant to Section 113 of the Clean Air Act (CAA). This PSD permit does not relieve Pinecrest of the responsibility to comply with any other applicable provisions of the CAA (including applicable implementing regulations in 40 CFR Parts 51, 52, 60, 61, 72 through 75, and 98) or other federal and state requirements (including the state PSD program that remains under approval at 40 CFR § 52.2303).

In accordance with 40 CFR § 124.15(b)(3), this PSD Permit becomes effective immediately upon issuance of this final decision.

Wren Stenger

7/31/14

Wren Stenger, Director — Date

Multimedia Planning and Permitting Division

Pinecrest LLC (PSD-TX-1298-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Final Permit Conditions

PROJECT DESCRIPTION

Pinecrest Energy Center is proposing to construct a new combined cycle electric generating plant (PEC) in Angelina County, Texas. PEC will generate 637 - 735 megawatts (MW) of gross electrical power near the City of Lufkin. The PEC will consist of the following sources of GHG emissions:

- Two natural gas-fired combustion turbines equipped with lean pre-mix low-NOx combustors;
- Two natural gas-fired duct burner systems;
- Natural gas piping and metering;
- One diesel fuel-fired emergency electrical generator engine;
- One diesel fuel-fired fire water pump engine;
- One natural gas-fired auxiliary boiler; and
- Electrical equipment insulated with sulfur hexafluoride (SF_6).

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

FIN	EPN	Description
CTG1/HRSG1 CTG2/HRSG2	U1-STK U2-STK	2 Natural Gas-Fired Combined Cycle Combustion Turbines (Combustion Units). The combustion turbines are equipped with heat recovery steam generators (HRSG) and selective catalytic reduction (SCR).
AUXBLR	AUXBLR	1 Auxiliary Boiler (Combustion Unit). The boiler has a maximum design heat input rate of 150 MMbtu/hr, and is fired with natural gas.
FWP1	FWP1-STK	1 Fire Water Pump (Combustion Unit). 500 horsepower (hp) Diesel-Fired Fire Water Pump rated at 3.4 MMBtu/hr and limited to 100 hours of operation per year for non-emergency activities.
EMGEN1	EMGEN1-STK	1 Emergency Generator (Combustion Unit). 1,072 horsepower (hp) Diesel-Fired Emergency Generator rated at 7.9 MMBtu/hr and limited to 100 hours of operation per year for non-emergency activities.
SF6-FUG	SF6-FUG	SF_6 Insulated Electrical Equipment (i.e., circuit breakers) with 400 lb SF_6 capacity.
NG-FUG	NG-FUG	Process Fugitives.

I. GENERAL PERMIT CONDITIONS

A. PERMIT EXPIRATION

As provided in 40 CFR §52.21(r), this PSD permit shall become invalid if construction:

1. is not commenced (as defined in 40 CFR §52.21(b)(9)) within 18 months after the approval takes effect;

2. is discontinued for a period of 18 months or more; or

3. is not completed within a reasonable time.

Pursuant to 40 CFR § 52.21(r), EPA may extend the 18-month period upon a written satisfactory showing that an extension is justified.

B. PERMIT NOTIFICATION REQUIREMENTS

Permittee shall notify EPA Region 6 in writing or by electronic mail of the:

1. date construction is commenced, postmarked within 30 days of such date;

2. actual date of initial startup, as defined in 40 CFR § 60.2, postmarked within 15 days of such date; and

3. date upon which initial performance tests will commence, in accordance with the provisions of Section VI, postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol required pursuant to Condition VI.C.

C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and maintenance, Permittee shall, to the extent practicable, maintain and operate the facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA, which may include, but is not limited to, monitoring results, review of operating maintenance procedures and inspection of the facility.

D. **MALFUNCTION REPORTING**

1. Permittee shall notify EPA by mail within 48 hours following the discovery of any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner, which results in an increase in GHG emissions above the allowable emission limits stated in Sections II and III of this permit.

2. Within 10 days of the restoration of normal operations after any failure described in I.D.1., Permittee shall provide a written supplement to the initial notification that includes a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Section II and III, and the methods utilized to mitigate emissions and restore normal operations.

3. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

E. **RIGHT OF ENTRY**

EPA authorized representatives, upon the presentation of credentials, shall be permitted:

1. to enter the premises where the facility is located or where any records are required to be kept under the terms and conditions of this PSD permit;

2. during normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD permit;

3. to inspect any equipment, operation, or method subject to requirements in this PSD permit; and,

4. to sample materials and emissions from the source(s).

F. **TRANSFER OF OWNERSHIP**

In the event of any changes in control or ownership of the facilities to be constructed, this PSD permit shall be binding on all subsequent owners and operators. Permittee shall notify the succeeding owner and operator of the existence of the PSD permit and its conditions by letter; a copy of the letter shall be forwarded to EPA Region 6 within thirty days of the letter signature.

G. SEVERABILITY

The provisions of this PSD permit are severable, and, if any provision of the PSD permit is held invalid, the remainder of this PSD permit shall not be affected.

H. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

Permittee shall construct this project in compliance with this PSD Permit, the application on which this permit is based, the TCEQ PSD permit PSD-TX-1298 (when issued) and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

I. ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute BACT
	Best Available Control Technology
BSCFD	Billion Standard Cubic Feet per Day
CAA	Clean Air Act
CC	Carbon Content
CCS	Carbon Capture and Sequestration
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CT	Combustion Turbine
DLNB	Dry Low-NO_x Burner
dscf	Dry Standard Cubic Foot
EF	Emission Factor
EPN	Emission Point Number
FIN	Facility Identification Number
FR	Federal Register
GHG	Greenhouse Gas
gr	Grains
GWP	Global Warming Potential
HHV	High Heating Value
hr	Hour
LAER	Lowest Achievable Emission Rate
lb	Pound
LDAR	Leak Detection and Repair
MMBtu	Million British Thermal Units
MSS	Maintenance, Start-up and Shutdown
mtpa	Million Tons per Annum
NNSR	Nonattainment New Source Review
N_2O	Nitrous Oxides
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance and/or Quality Control
SCFH	Standard Cubic Feet per Hour
SCR	Selective Catalytic Reduction
SF_6	Sulfur Hexafluoride
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TPY	Tons per Year
USC	United States Code
VOC	Volatile Organic Compound

II. Annual Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month rolling total, shall not exceed the following if the General Electric 7FA.05 is selected as the combustion turbine model:

Table 1A. Annual Emission Limits[1] - General Electric 7FA.05

FIN	EPN	Description[2]	GHG Mass Basis		TPY CO e[2,3]	BACT Requirements	
				TPY[2]			
CTG1/HRSG1	U1-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,446,186	1,447,653	942.0 lb CO_2/MWh (gross) with duct burning.[5] See Special Condition III.A.1. Startup emissions limited to 500 hours per year and 83 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.	
			CH_4	26.8			
			N_2O	2.7			
CTG2/HRSG2	U2-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,446,186	1,447,653	942.0 lb CO_2/MWh (gross) with duct burning.[5] See Special Condition III.A.1. Startup emissions limited to 500 hours per year and 83 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.	
			CH_4	26.8			
			N_2O	2.7			
AUXBLR	AUXBLR	Auxiliary Boiler	CO_2	7,680	7,687	Good Combustion and Operating Practices. Limit to 876 hours of operation per year. See Special Conditions III.B.	
			CH_4	0.14			
			N_2O	0.01			
EMGEN1	EMGEN1 -STK	Emergency Generator	CO_2	64	64	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.	
			CH_4	No Numerical Limit Established[6]			
			N_2O	No Numerical Limit Established[6]			
FWP1	FWP1-STK	Fire Water Pump	CO_2	28	28	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.	
			CH_4	No Numerical Limit Established[6]			
			N_2O	No Numerical Limit Established[6]			

FIN	EPN	Description	GHG Mass Basis		TPY CO e[2,3]	BACT Requirements
				TPY[2]		
NG-FUG	NG-FUG	Natural Gas Fugitives [6,8]	CO_2	0.81	510	Implementation of AVO Monitoring. See Special Condition III.D.
			CH_4	20.4		
SF6-FUG	SF6-FUG	SF_6 Insulated Equipment[6]	SF_6	No Numerical Limit Established[6]	23	Instrumented monitoring and alarm. See Special condition III.D.
Totals[7]			**CO_2**	**2,900,145**	**2,903,627**	
			CH_4	**74**		
			N_2O	**5.4**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling total.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298, SF_6 = 22,800
4. The annual emissions limit for the combustion turbines is based on operating at maximum duct burner firing for 8,260 hours per year, and operating during startup, shutdown, and maintenance (MSS) for 500 hours per year. The annual emission limit includes emissions from MSS.
5. The lb/MWh BACT limit for the combustion turbine does not apply during startup.
6. All values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
7. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. Total emissions are for information only and do not constitute an emission limit.
8. EPN NG-FUG includes fugitive emissions from piping and other components, as well as emissions from gaseous fuel line purging and maintenance/repair/replacement of fugitive components.

Annual emissions, in tons per year (TPY) on a 12-month rolling total, shall not exceed the following if the Siemens SGT6-5000F(4) is selected as the combustion turbine model:

Table 1B. Annual Emission Limits[1] - Siemens SGT6-5000F(4)

FIN	EPN	Description[2]	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
CTG1/HRSG1	U1-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,398,427	1,399,842	909.2 lb CO_2/MWh (gross) with duct burning.[5] See Special Condition III.A.1. Startup emissions limited to 500 hours per year and 84 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.
			CH_4	25.9		
			N_2O	2.6		
CTG2/HRSG2	U2-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,398,427	1,399,842	909.2 lb CO_2/MWh (gross) with duct burning.[5] See Special Conditions III.A.1. Startup emissions limited to 500 hours per year and 84 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.
			CH_4	25.9		
			N_2O	2.6		
AUXBLR	AUXBLR	Auxiliary Boiler	CO_2	7,680	7,687	Good Combustion and Operating Practices. Limit to 876 hours of operation per year. See Special Conditions III.B.
			CH_4	0.14		
			N_2O	0.01		
EMGEN1	EMGEN1 -STK	Emergency Generator	CO_2	64	64	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
FWP1	FWP1-STK	Fire Water Pump	CO_2	28	28	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
NG-FUG	NG-FUG	Natural Gas Fugitives[6]	CO_2	0.81	510	Implementation of AVO Monitoring. See Special Condition III.D.
			CH_4	20.4		

FIN	EPN	Description[2]	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
SF6-FUG	SF6-FUG	SF_6 Insulated Equipment	SF_6	No Numerical Limit Established[6]	23	Instrumented monitoring and alarm. See Special condition III.D.
Totals[7]			**CO_2**	**2,804,627**	**2,808,007**	
			CH_4	**72.3**		
			N_2O	**5.2**		

1. Compliance with the annual emission limits (tons per year) is based on a 12 month rolling total.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298, SF_6 = 22,800
4. The annual emissions limit for the combustion turbines is based on operating at maximum duct burner firing for 8,260 hours per year, and operating during startup, shutdown, and maintenance (MSS) for 500 hours per year. The annual emission limit includes emissions from MSS.
5. The lb/MWh BACT limit for the combustion turbine does not apply during startup.
6. All values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
7. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. Total emissions are for information only and do not constitute an emission limit.
8. EPN NG-FUG includes fugitive emissions from piping and other components, as well as emissions from gaseous fuel line purging and maintenance/repair/replacement of fugitive components.

Annual emissions, in tons per year (TPY) on a 12-month rolling total, shall not exceed the following if the Siemens SGT6-5000F(5) is selected as the combustion turbine model:

Table 1C. Annual Emission Limits[1] - Siemens SGT6-5000F(5)

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
U1-STK	U1-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,569,269	1,570,854	912.7 lb CO_2/MWh (gross) with duct burning.[5] See Special Condition III.A.1. Startup emissions limited to 500 hours per year and 85 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.
			CH_4	29		
			N_2O	2.9		
U2-STK	U2-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,569,269	1,570,854	912.7 lb CO_2/MWh (gross) with duct burning.[5] See Special Conditions III.A.1. Startup emissions limited to 500 hours per year and 85 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.
			CH_4	29		
			N_2O	2.9		
AUXBLR	AUXBLR	Auxiliary Boiler	CO_2	7,680	7,687	Good Combustion and Operating Practices. Limit to 876 hours of operation per year. See Special Conditions III.B.
			CH_4	0.14		
			N_2O	0.01		
EMGEN1	EMGEN1 -STK	Emergency Generator	CO_2	64	64	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
FWP1	FWP1-STK	Fire Water Pump	CO_2	28	28	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
NG-FUG	NG-FUG	Natural Gas Fugitives [6,8]	CO_2	0.8	510	Implementation of AVO Monitoring. See Special Condition III.D.
			CH_4	20.4		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
SF6-FUG	SF6-FUG	SF_6 Insulated Equipment	SF_6	No Numerical Limit Established[6]	23	Instrumented monitoring and alarm. See Special condition III.D.
Totals[7]			**CO_2**	**3,146,311**	**3,150,030**	
			CH_4	**78.7**		
			N_2O	**5.8**		

1. Compliance with the annual emission limits (tons per year) is based on a 12 month rolling total.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298, SF_6 = 22,800
4. The annual emissions limit for the combustion turbines is based on operating at maximum duct burner firing for 8,260 hours per year, and operating during startup, shutdown, and maintenance (MSS) for 500 hours per year. The annual emission limit includes emissions from MSS.
5. The lb/MWh BACT limit for the combustion turbine does not apply during startup.
6. All values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
7. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. Total emissions are for information only and do not constitute an emission limit.
8. EPN NG-FUG includes fugitive emissions from piping and other components, as well as emissions from gaseous fuel line purging and maintenance/repair/replacement of fugitive components.

III. SPECIAL PERMIT CONDITIONS

A. Requirements for Combustion Turbine Generators (CTG) and Heat Recovery Steam Generators (HRSG) (EPNs: U1-STK and U2-STK)

The Permittee shall comply with Table 1A, 1B, or 1C depending on the selection of manufacturer and model of combined cycle combustion turbine selected. Upon selection of a combustion turbine model, Pinecrest must submit a permit application amendment to remove the turbine models not selected.

1. Combustion Turbine Generator (CTG) BACT Emission Limits

Table 2. BACT Emission Limits for Combustion Turbines on a 12 month rolling average

Turbine Model	Gross Heat Rate, with duct burner firing (Btu/kWh) (HHV)	Output Based Emission Limit (lb CO_2/MWh) gross with duct burning	Startup Emission Limit (tons CO_2/hr)
General Electric 7FA.05	7,925.0	942.0	83
Siemens SGT6-5000F(4)	7,649.0	909.2	84
Siemens SGT6-5000F(5)	7,679.0	912.7	85

a. Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days of the date of initial startup of the combustion turbine generators, the Permittee shall perform an initial emission test for CO_2 and use emission factors from 40 CFR Part 98. The Permittee shall ensure that GHG emissions from the Combustion Turbine Generator and heat recovery steam generator (U1-STK and U2-STK) into the atmosphere do not exceed the limits in lbs CO_2/MWh (gross) from Table 2 during the test. To determine this BACT emission limit, Permittee shall calculate the limit based on the measured hourly energy output (MWh (gross)) while the CTG is operating at or above 90% of its design capacity with duct burner firing, and the results shall be corrected to ISO conditions (59^{o}F, 14.7 psia, and 67% humidity). If the CTG does not meet the design emissions limit, then the Permittee shall remedy the CTG's failure to meet the design emissions limit, will make corrections to the CTG, and will only combust fuel to perform required tuning and modifications necessary to demonstrate compliance.

b. The hourly gross electric output from the steam turbine shall be apportioned based on either the measured steam load or measured heat input. A plan to demonstrate the apportionment of the gross electric output shall be submitted within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days of the date of initial startup of the combustion turbine generator.

c. The CO_2 mass emission values shall be calculated over each operational hour of the compliance period and summed. The summed hourly CO_2 mass emission values shall be divided by the combined sum of the total gross electrical output from the steam turbine (as determined by the corresponding apportionment calculations represented in the plan) and the total gross electrical load from the combustion turbine generator. The resulting quotient is added to the sum of quotients of the previous 11 operating months and divided by 12 to determine compliance with the 12-month rolling average.

d. Upon initial demonstration that the combustion turbine complies with the emission limit via emission tests, the Permittee shall not exceed the combustion turbine and duct burner annual firing rate, Btu/kWh (HHV) from Table 2 on a 12-month rolling average. To determine the limit, the Permittee shall calculate the average hourly heat input rate over the applicable compliance period consistent with equation F-20 and procedure provided in 40 CFR Part 75, Appendix F § 5.5.2 and the GCV of the fuel combusted for the corresponding compliance period. Add the quotient to the sum of the quotients of the previous 11 operating months and divide by 12 to determine the 12-month rolling average.

e. The Permittee shall not discharge or cause the discharge of emissions into the atmosphere in excess of the limits in tons of CO_2e on a 12-month rolling total as listed in Table 1.

2. Monitoring of CO_2 Emissions for EPNs: U1-STK and U2-STK

a. Upon initial demonstration that the combustion turbine generators are in compliance with the emissions limit via an emission test, the Permittee shall not discharge or cause the discharge of emissions from the Combustion Turbine Generator (CTG) and heat recovery steam generator (HRSG) (EPNs U1-STK and U2-STK) into the atmosphere in excess of limits in tons of CO_2e on a 12-month rolling average as listed in Table 1A, 1B, or 1C, at all times including periods of startup and shutdown. To determine the amount of CO2e, the Permittee shall calculate the amount of CO_2, CH_4 and N_2O in tpy based on the equation G-4 of 40 CFR 75, Appendix G and 40 CFR Part 98, Appendix C. The tpy values are multiplied by the respective Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1 to calculate the amount of CO_2e emitted in Tons/hr for the operational month. The resulting CO_2e value is added to the previous 11 months to determine the 12 month rolling total of CO_2e emissions. The Permittee shall determine compliance with the CH_4 and N_2O emissions on a 12-month rolling total. The Permittee shall determine compliance with the CH4 and N_2O emissions limits contained in Section II using the default CH_4 and N_2O emission factors contained in Table C-2 of 40 CFR Part 98 and the measured actual hourly heat input (HHV).

b. As an alternative, the Permittee may install and operate a volumetric stack gas flow monitor and associated data acquisition and handling system in accordance with the CO_2 CEMS system provided in 40 CFR § 75.10(a)(3) and (a)(5). If a CO_2 CEMS system is utilized, the hourly CO_2 emission value shall be measured by installing and operating a volumetric stack gas flow monitor or calculating the volumetric stack gas flow by the procedures of 40 CFR Part 75, Appendix D and associated data acquisition and handling system in accordance with the CO_2 CEMS system provided in 40 CFR § 75.10.

c. In accordance with 40 CFR Part 75, Appendix D and 40 CFR Part 60, the Permittee shall ensure that all required fuel flow meters are installed, a periodic schedule for GCV fuel sampling is initiated and all certification tests are completed on or before the earlier of 90 unit operating days or 180 calendar days after the date the unit commences commercial operation (as defined in 40 CFR § 72.2).

d. The Permittee shall ensure compliance with the specifications and test procedures for fuel flow meter and/or CO_2 emission monitoring system at stationary sources, 40 CFR Part 75 and 40 CFR Part 60.

e. The Permittee shall meet the appropriate quality assurance requirements specified in 40 CFR Part 75, Appendixes D and F and 40 CFR Part 60 for the fuel flow meter and/or CO_2 emission monitoring system.

3. U1-STK and U2-STK Combustion Turbine Work Practice and Operational Requirements

a. The combined cycle combustion turbine and duct burners are limited to burning only pipeline natural gas. The gross calorific value of the fuel shall be determined monthly by the procedures contained in 40 CFR Part 75, Appendix F, § 5.5.2, and records shall be maintained of the monthly fuel gross calorific value for a period of five years. Upon request, the Permittee shall provide a sample and/or analysis of the fuel fired in the combustion turbine and/or duct burners or shall allow a sample to be taken by EPA for analysis.

b. The flow rate of the fuel combusted in the combustion turbine and duct burners shall be measured and recorded using an in-line flow meter and automatically record the data with a data acquisition and handling system. The steam load and/or heat input to the steam turbine shall also be measured and recorded.

c. The Permittee shall measure and record the energy output (MWh, gross) on an hourly basis.

d. On or before the date of initial performance test required by 40 CFR § 60.8, and thereafter, the Permittee shall install, and continuously operate, and maintain the HRSGs equipped with a SCR so emissions are at or below the emissions limits specified in this permit and TCEQ permit PSDTX1298.

e. The Permittee shall perform an annual compliance test, at or above 90% of maximum load operations for the atmospheric conditions which exist during testing, corrected to ISO conditions to demonstrate compliance with the proposed heat rate in Table 2.

f. On or after initial performance testing, the Permittee shall use BACT practices and designs represented in the permit application.

4. Requirements during Combustion Turbine (EPNs: U1-STK and U2-STK) Startup and Shutdown

a. Permittee shall minimize emissions during start-up and shutdown activities by operating and maintaining the facility and associated air pollution control equipment in accordance with good air pollution control practices, safe operating practices, and protection of the facility.

b. Emissions during startup and shutdown activities shall be minimized by limiting the duration of operation in startup and shutdown mode as follows:

i. A startup is defined as the period that begins when the data acquisition and handling system measures fuel flow to the combustion turbine and ends when the combustion turbine generator load reaches 60 percent. A planned startup for each combustion turbine is limited to 360 minutes per event.

ii. A shutdown is defined as the period that begins when the combustion turbine generator output drops below 60 percent load and ends when there is no longer measureable fuel flow to the combustion turbine. A planned shutdown of the combustion turbine is limited to 60 minutes per event.

c. Startup and shutdown emissions shall not exceed the BACT emission limits in Table 2.

d. The maximum heat input shall be limited to the values identified in Table 3 during startup.

e. Startups are limited to 500 hours on a 12-month rolling basis.

f. The startup emissions and heat input limits are also shown in Table 3 below.

Table 3. Startup Emissions and Heat Input Limitations

Turbine Model	BACT Emission Limit (tons CO_2/hr)	Annual Emission Limit (tons CO_2e/yr)	Maximum Heat Input (MMBtu/hr)
GE 7FA.05	83	41,678	1401.2
SGT6-5000F(4)	84	41,847	1406.9
SGT6-5000F(5)	85	42,475	1428.0

g. Permittee must record the time, date, fuel heat input (HHV) in MMBtu/hr and duration of each startup and shutdown event in order to calculate total CO_2e emissions. The records must include hourly CO_2 emission levels as measured by the fuel flow meter and/or O_2 emission monitor (or CO_2 CEMS with volumetric stack gas flowrate) and the calculations based on the actual heat input for the CO_2, CO_2e, O_2, N_2O, and CH_4 emissions during each startup and shutdown event based on the equations represented in the permit application. These records must be kept for five (5) years following the date of such event.

h. The 12-month rolling average BACT emission limitations in Special Condition III.A.1. does not include periods of startup.

B. Requirements for Auxiliary Boiler (EPN: AUXBLR)

1. Boiler shall combust only pipeline quality natural gas.
2. Permittee shall measure and record the fuel flow rate using an inline flow meter and automatically record the data with a data acquisition and handling system.
3. Permittee shall calibrate and perform preventative maintenance check of the fuel gas flow meters and document annually.
4. Permittee shall perform cleaning of the burner tips annually, at a minimum.
5. Permittee shall perform cleaning of the convection section tubes annually, at a minimum.
6. The maximum firing rate for the auxiliary boiler shall not exceed 150 MMBtu/hr.
7. The one-hour maximum firing rate shall be calculated daily to demonstrate compliance with the firing rate in III.B.6.
8. Total firing hours of the auxiliary boiler must not exceed 876 hours per year.
9. Records of firing hours shall be recorded daily. A 12-month rolling total of boiler hours of operation shall be calculated to demonstrate compliance with the limitation of hours in III.B.8.
10. Permittee shall install, operate, and maintain an automated air/fuel control system.
11. Permittee shall calibrate and perform preventative maintenance on the air/fuel control analyzers once per quarter, at a minimum.
12. Permittee shall install, operate, and maintain an O2 analyzer on the boiler.
13. Oxygen analyzers shall continuously monitor and record oxygen concentration in the boiler. It shall reduce the oxygen readings to an averaging period of 6 minutes or less and record it at that frequency.
14. The oxygen analyzers shall be quality-assured at least quarterly using cylinder gas audits (CGAs) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.2, with the following exception: a relative accuracy test audit is not required once every four quarters (i.e., four successive quarterly CGAs may be conducted).
15. Compliance with the Annual Emission Limit shall be demonstrated on a 12-month total, rolling monthly, calculated in accordance with 40 CFR § 98.33(a)(1)(i).

C. Requirements for the Fire Water Pump (EPN: FWP1-STK) and Emergency Generator (EPN: EMGEN1-STK)

1. The Fire Water Pump (FWP1-STK) and Emergency Generator (EMGEN1-STK) are authorized to fire diesel fuel containing no more than 0.5 percent sulfur by weight.

Upon request, Permittee shall provide a sample and/or an analysis of the fuel-fired in the emission units (EMGEN1-STK and FWP1-STK) or shall allow a sample to be taken by EPA for analysis to demonstrate the percent sulfur of the fuel.

2. The Fire Water Pump and Emergency Generator are limited to 100 hours of non-emergency operation per year for each unit and a heat input value of 3.4 MMBtu/hr and 7.9 MMBtu/hr for the Fire Water Pump and the Emergency Generator, respectively. Compliance with the 100 hour non-emergency operational requirement is determined on a 12-month rolling basis.
3. The Fire Water Pump and Emergency Generator shall meet the applicable monitoring and recordkeeping requirements as required in 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
4. Permittee shall install and maintain an operational non-resettable elapsed time meter for the Fire Water Pump and Emergency Generator.
5. Permittee shall maintain a file of all records, data measurements, reports and documents related to the operation of the Fire Water Pumps and Emergency Generator, including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to performance tests and monitoring of the emergency generator and fire pump equipment; for each diesel fuel oil delivery, documents from the fuel supplier certifying compliance with the fuel sulfur content limit of Special Condition III.C.1., fuel heat input values and hours of operation required in Special Condition III.C.2.; and all other information required by this permit recorded in a permanent form suitable for inspection. The file must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.

D. Requirements for Fugitive Emission Sources (EPNs: NG-FUG and SF6-FUG)

1. The Permittee shall implement an auditory/visual/olfactory (AVO) method for detecting leaking from natural gas piping components and make observations on a daily basis.
2. For emission unit SF6-FUG, SF_6 emissions shall be calculated annually (calendar year) in accordance with the mass balance approach provided in equation DD-1 of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use, 40 CFR Part 98, Subpart DD. Permittee shall not exceed insulated circuit breaker SF_6 capacity exceeding 400 lbs.
3. Permittee shall equip the circuit breakers with a low pressure alarm and a low pressure lockout. The SF_6 leak detection system shall be able to detect a leak of at least 1 lb per year.
4. Permittee shall maintain a file of all records, data measurements, reports and documents related to the fugitive emission sources including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records

relating to compliance with the Monitoring and Quality Assurance and Quality Control (QA/QC) procedures outlined in 40 CFR § 98.304.

5. The Permittee provided data to show that minimal quantities of natural gas are released to the atmosphere during turbine fuel line shutdown maintenance and when performing repair or maintenance on small equipment and fugitive components.

IV. RECORDKEEPING AND REPORTING

1. In order to demonstrate compliance with the GHG emission limits in Table 1, the Permittee will monitor the following parameters and summarize the data on a calendar month basis.

    a. Operating hours for all air emission sources;
    b. The natural gas fuel usage for all combustion sources, using continuous fuel flow monitors (a group of equipment can utilize a common fuel flow meter, as long as actual fuel usage is allocated to the individual equipment based upon actual operating hours and maximum firing rate); and
    c. Annual fuel sampling for natural gas.

2. Permittee shall implement an AVO program and keep records of the monitoring results, as well as the repair and maintenance records.
3. Permittee shall maintain all records, data, measurements, reports, and documents related to the operation of the facility, including, but not limited to, the following: all records or reports pertaining to significant maintenance performed on any system or device at the facility; duration of startup and shutdown; the initial startup period for the emission units; pollution control units; malfunctions; all records relating to performance tests, calibrations, checks, and monitoring of combustion equipment; duration of an inoperative monitoring device and emission units with the required corresponding emission data; and all other information required by this permit recorded in a permanent form suitable for inspection. The records must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.
4. Permittee shall maintain records of all GHG emission units and CO_2 emission certification tests and monitoring and compliance information required by this permit.
5. Permittee shall maintain records and submit a written report of all GHG excess emissions to EPA semi-annually, except when more frequent reporting is specifically required by an applicable subpart or the Administrator or authorized representative, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30th day following the end of each semi-annual period and shall include the following:

    a. Time intervals, data and magnitude of the excess emissions, the nature and cause (if known), corrective actions taken and preventive measures adopted;

b. Applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time);
c. A statement in the report of a negative declaration, that is, a statement when no excess emissions occurred or when the monitoring equipment has not been inoperative, repaired or adjusted; and
d. Any failure to conduct any required source testing, monitoring, or other compliance activities.

6. Excess emissions shall be defined as any period in which the facility emissions exceed a maximum emission limit set forth in this permit.
7. Excess emissions indicated by GHG emission source certification testing or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.
8. All records required by this PSD permit shall be retained and remain accessible for not less than 5 years following the date of such measurements, maintenance, and reporting.

V. SHAKEDOWN PERIODS

The combustion turbine emission limits and requirements in conditions II., III.A.1., and III.B. shall not apply during combustion shakedown periods. Shakedown is defined as the period beginning with initial startup and ending no later than initial performance testing, during which the Permittee conducts operational and contractual testing and tuning to ensure the safe, efficient and reliable operation of the plant. The shakedown period shall not exceed the time period for performance testing as specified in 40 CFR § 60.8. The requirements of special condition I.C. of this permit shall apply at all times.

VI. PERFORMANCE TESTING

A. The Permittee shall perform stack sampling and other testing to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the stacks of the Combustion Turbines and HRSGs (U1-STK and U2-STK) and the Auxiliary Boiler (AUXBLR) to determine the initial compliance with the CO_2 emission limits established in this permit. Sampling shall be conducted in accordance with 40 CFR § 60.8 and EPA Method 3a or 3b for the concentration of CO_2.

1. Multiply the CO_2 hourly average emission rate determined under maximum operating test conditions by 8,760 hours for the combustion turbines and 876 hours for the auxiliary boiler.
2. If the above calculated CO_2 emission total does not exceed the TPY specified on Table 1, no compliance strategy needs to be developed.
   If the above calculated CO_2 emission total exceeds the TPY specified in Table 1, the facility shall:

a. Document the potential to exceed in the test report; and
b. Explain within the report how the facility will assure compliance with the CO_2 emission limit listed in Table 1.

B. Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility, performance tests(s) must be conducted and a written report of the performance testing results furnished to EPA. Additional sampling may be required by TCEQ or EPA.

C. Permittee shall submit a performance test protocol to EPA no later than 30 days prior to the test to allow review of the test plan and to arrange for an EPA observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol, and any changes required by EPA.

D. The turbine shall be tested at or above 90% of maximum load operations for the atmospheric conditions which exist during testing. The duct burners shall be tested at their maximum firing rate within the mechanical limits of the equipment for the atmospheric conditions which exists during the performance test while the turbine is operating as close to base load as possible. The tested turbine load shall be identified in the sampling report. The permit holder shall present in the performance test protocol the manner in which stack sampling will be executed in order to demonstrate compliance with the emissions limits contained in Section II.

E. Air emissions from each HRSG exhaust stack shall be tested while firing at the minimum load in the normal operating range. The normal operating range consistent with emission limits is to be determined during stack testing. Air emissions that will be sampled and analyzed while at the minimum load include (but are not limited to) CO_2.

F. Performance tests must be conducted under such conditions to ensure representative performance of the affected facility. The owner or operator must make available to EPA such records as may be necessary to determine the conditions of the performance tests.

G. The owner or operator shall provide, or cause to be provided, performance testing facilities as follows:

1. Sampling ports adequate for test methods applicable to this facility,
2. Safe sampling platform(s),
3. Safe access to sampling platform(s), and
4. Utilities for sampling and testing equipment.

H. Unless otherwise specified, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For purposes of determining compliance with an applicable standard, the arithmetic mean of the results of the three runs shall apply.

VII. Agency Notifications

Permittee shall submit GHG permit applications, permit amendments, and other applicable permit information to:

Multimedia Planning and Permitting Division
EPA Region 6
1445 Ross Avenue (6 PD-R)
Dallas, TX 75202
Email: Group R6AirPermits@EPA.gov

Permittee shall submit a copy of all compliance and enforcement correspondence as required by this Approval to Construct to:

Compliance Assurance and Enforcement Division
EPA Region 6
1445 Ross Avenue (6EN)
Dallas, TX 75202