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-979-GHG
PERMITTEE:	Calpine Corporation 717 Texas, Suite 1000 Houston, TX 77002
FACILITY NAME:	Calpine Corporation, Deer Park Energy Center (DPEC) LLC
FACILITY LOCATION:	5665 Highway 225 Deer Park, TX 77536

Pursuant to the provisions of the Clean Air Act (CAA), Subchapter I, Part C (42 U.S.C. Section 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 as published at 76 FR 25178),the U.S. Environmental Protection Agency, Region 6 (EPA) is issuing a *Prevention of Significant Deterioration* (PSD) permit to the Calpine Corporation, Deer Park Energy Center (DPEC) LLC for Greenhouse Gas (GHG) emissions. The Permit applies to the two-phase construction of a new 180 megawatt (MW) natural gas-fired combined-cycle combustion turbine, identified as CTG5/HRSG5, to augment the existing power generation at the existing facility located in Deer Park, Texas.

Calpine Corporation is authorized to construct at the Calpine Corporation, Deer Park Energy Center (DPEC) 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-979. 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 Calpine Corporation 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), this PSD Permit becomes effective thirty (30) days after the service of notice of this final decision unless review is requested on the permit pursuant to 40 CFR §124.19.

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Carl E. Edlund, P.E, Director
Multimedia Planning and Permitting Division

Date

Calpine Corporation, Deer Park Energy Center (DPEC) LLC (PSD-TX-979-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Final Permit Conditions

PROJECT DESCRIPTION

The proposed facility is a natural gas-fired combined-cycle electric generating unit at the Deer Park Energy Center (DPEC) LLC power plant in Harris County, Texas. With this construction permit, Calpine Corporation will construct a new natural gas-fired combined-cycle combustion turbine generator (CTG) unit, identified as CTG5/HRSG5, with a generating capacity of approximately 180 MW which is of the similar design and output as the other existing four (4) natural gas-fired combined-cycle combustion turbine units at the plant. Construction will be completed in two phases: in phase one, a new Siemens FD2-series turbine will be constructed; in the second phase, the FD2 turbine which will be modified and upgraded to the FD3-series within the statutory time lines as defined by this permit. The steam produced from the new combustion turbine will exhaust to a dedicated Heat Recovery Steam Generator (HRSG) to produce steam. The steam produced from the HRSG is routed to either the existing steam turbine unit to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid or may be sold for use at an adjacent industrial facility.

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

Emission Unit Id. No.	Description
CTG5/HRSG5 (FD2-Series) (Initial Phase)	Natural Gas-Fired Siemen FD2-Series 501F Combustion Turbine Generator (CTG5) rated at a maximum base-load electric output of approximately 168 MW and venting to a dedicated Heat Recovery Steam Generator (HRSG5) that is equipped with a Selective Catalytic Reduction (SCR).
CTG5/HRSG5 (FD3-Series) (Final Phase)	Natural Gas-Fired Siemen FD3-Series 501F Combustion Turbine Generator (CTG5) rated at a maximum base-load electric output of approximately 180 MW and venting to a dedicated Heat Recovery Steam Generator (HRSG5) that is equipped with a Selective Catalytic Reduction (SCR).
NG-FUG	Fugitive Natural Gas emissions from piping components (including valves and flanges)
SF6-FUG	SF_6 Insulated Electrical Equipment (i.e., circuit breakers) consisting of one new 72 lb SF_6 insulated generator circuit breaker,

I. GENERAL PERMIT CONDITIONS

A. PERMIT EXPIRATION

Pursuant to 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 eighteen (18) months after the approval takes effect; or

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

3. is not completed within a reasonable time; and,

4. EPA may extend the eighteen (18) month period upon a 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 thirty (30) calendar days of such date;

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

3. date upon which initial performance tests will commence, in accordance with the provisions of Section V, postmarked not less than thirty (30) calendar days prior to such date. Notification may be provided with the submittal of the performance test protocol required pursuant to Section V.E; and

4. date upon which initial certification tests of fuel flow meter and determination of the GCV (Gross Calorific Value) and associated data acquisition and handling system in accordance with 40 CFR 75, Appendix D. Additionally, the initial certification or recertification application shall be submitted for the fuel flow meter as required by 40 CFR 75, Appendix D.

5. date upon which certification tests of the CO_2 CEMS will commence, if Calpine chooses to install a CO_2 continuous emission monitoring system (CEMS), in accordance with 40 CFR § 75.61(a)(1)(i) and 40 CFR Part 60, Appendix B, Performance Specification 3. Additionally, the initial certification or recertification application shall be submitted for the CO_2 CEMS as required by 40 CFR 75.63.

6. date upon which the FD3-series combustion turbine generator is in commercial operation

or date eighteen (18) months after the completion of initial performance testing, or whichever comes first.

C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and malfunction, 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 forty-eight (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 CO_2 emissions above the allowable emission limits stated in Section II of this permit.

2. Within ten (10) days of the restoration of normal operations after any failure described in Section I.D.1, the 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 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 (30) 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 by a court of competent jurisdiction, the remainder of this PSD Permit shall not be affected.

H. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

Permittee shall construct and operate this project in compliance with this PSD Permit, the application on which this permit is based, the TCEQ PSD Permit No. PSD-TX-979-GHG, as finalized 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

AVO	Audio, Visual, and Olfactory
BACT	Best Available Control Technology
Btu	British thermal unit
CAA	Clean Air Act
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DCS	Distributed Control System
DPEC	Deer Park Energy Center
dscf	Dry Standard Cubic Foot
EPN	Emission Point Number
ERCOT	Electric Reliability Council of Texas
FR	Federal Register
GHG	Greenhouse Gas
gr	Grains
GWP	Global Warming Potential
HHV	High Heating Value
hp	Horsepower
hr	Hour

HRSG	Heat Recovery Steam Generator
KWh	Kilowatt-hour
lb	Pound
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-hour
N_2O	Nitrous Oxides
NSPS	New Source Performance Standards
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance and/or Quality Control
RATA	Relative Accuracy Test Audit
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 Compounds

II. SPECIAL PERMIT CONDITIONS

A. Facility Emission Limits

The proposed BACT limits are in terms of efficiency measured in units of Btu of fuel energy consumed in order to generate a kilowatt of electric energy (Btu/kWh). The BACT limits for the heat rate in terms of Btu/kWh (HHV) on an annual basis will be the same for the FD2 configuration as the FD3 configuration. The FD3 configuration provides greater electrical output at high ambient temperatures during base load periods. Therefore, for the FD3, the potential annual electric generation (MWH) and fuel usage, as well as corresponding GHG emissions, will be higher on an annual basis. Consequently, the BACT limits, monitoring and recordkeeping requirements listed in this permit are identical for both the FD2- and FD3-series combined-cycle combustion turbine generators. Any output-based emissions, in tons of CO_2 per megawatt hour (tons/MWh) on a 30-day rolling average and annual emissions, in tons of CO_2e per year (TPY) on a 365-day rolling average basis shall not exceed the following:

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Table 1. Phase 1 Facility Emission Limits

Phase 1 of Construction							
Emission Unit	**Description**	**GHG Mass Basis**		**BACT**			
			GHG Potential Emissions (TPY)[2,3]		**Output-based BACT CO_2 Limit[1]**	**Tons per year CO_2e[2,3]**	**Annual BACT Limit (TPY CO_2e[2,3])**
CTG5 (FD2) / HRSG5	CTG5/HRSG5 Annual Emissions	CO_2	1,044,629	CO_2	0.460 tons/MWh 7,730 Btu/KWh	1,044,629	**1,045,635**
		CH_4	19.34	CH_4		406	
		N_2O	1.93	N_2O		599	
NG-FUG	Fugitive Natural Gas emissions from piping components (including valves & flanges)	CO_2	0.11	CO_2		0.11	**60**
		CH_4[4]	2.84	CH_4[4]		59.69	
SF6-FUG	SF_6 Insulated Electrical Equipment	SF_6	0.00018	SF_6		4.3	**4.3**

1. Compliance with the output-based emission limits (on a per hour basis) is based on a 30-day rolling average.
2. Compliance with the annual emission limits (tons per year) is based on a 365-day rolling average.
3. The tpy emission limits specified in this table are not to be exceeded for this facility and includes emissions only from the facility during normal operations and startup and shutdown activities.
4. Because the emissions from this unit are calculated to be 96% methane (CH_4), the remaining pollutant emission (CO_2) is not presented in the table.
5. Because the emissions from this unit are calculated to be over 99.9% carbon dioxide (CO_2), the remaining pollutant emissions (CH_4 and N_2O) are not presented in the table.

Table 2. Phase 2 Facility Emission Limits

Phase 2 of Construction							
Emission Unit	**Description**	**GHG Mass Basis**		**BACT**			
			GHG Potential Emissions (TPY)[2,3]		**Output-based BACT CO_2 Limit[1]**	**Tons per year CO_2e[2,3]**	**Annual BACT Limit (TPY CO_2e[2,3])**
CTG5 (FD3) / HRSG5	CTG5/HRSG 5 Annual Emissions	CO_2	1,062, 627	CO_2	0.460 tons/MWh 7,730 Btu/KWh	1,062, 627	**1,063,650**
		CH_4	19.67	CH_4		413	
		N_2O	1.97	N_2O		610	
NG-FUG	Fugitive Natural Gas emissions from piping components (including valves & flanges)	CO_2	0.11	CO_2		0.11	**60**
		CH_4[4]	2.84	CH_4[4]		59.69	
SF6-FUG	SF_6 Insulated Electrical Equipment	SF_6	0.00018	SF_6		4.3	**4.3**

1. Compliance with the output-based emission limits (on a per hour basis) is based on a 30-day rolling average.
2. Compliance with the annual emission limits (tons per year) is based on a 365-day rolling average.
3. The tpy emission limits specified in this table are not to be exceeded for this facility and includes emissions only from the facility during normal operations and startup and shutdown activities.
4. Because the emissions from this unit are calculated to be 96% methane (CH_4), the remaining pollutant emission (CO_2) is not presented in the table.
5. Because the emissions from this unit are calculated to be over 99.9% carbon dioxide (CO_2), the remaining pollutant emissions (CH_4 and N_2O) are not presented in the table.

B. Requirements for Combustion Turbine

1. Combustion Turbine Generator (CTG) BACT Emission Limits

a. Within 180 days of the date of initial startup of the FD2-series combustion turbine generator, 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 (CTG5) and heat recovery steam generator (HRSG5) into the atmosphere in excess of 0.460 tons CO_2/MWh (net), not including duct firing, during the test. To determine this BACT emission limit, Permittee shall calculate the limit based on the measured net hourly energy output (MWh (net)), the CTG is operating above 90% of its design capacity without duct burning 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, and shall not combust any fuel in the CTG until the Permittee has shown compliance with that limit during a subsequent emission test.

b. Upon demonstration that the FD2-series combustion turbine generator is in compliance with the design emissions limit via an emission test, the Permittee shall not discharge or cause the discharge of emissions from the Combustion Turbine Generator (CTG5) and heat recovery steam generator (HRSG5) into the atmosphere in excess of 0.460 ton CO_2/MWh (net) on a 30-day rolling average and shall not discharge or cause the discharge of emissions into the atmosphere in excess 1,045,635 tons of CO_2e on a 365-day rolling average. To determine this BACT emission limits, the Permittee shall calculate the limit based on the measured net hourly energy output (MWh (net)) and the tons of CO_2 calculated from the equations provided in 40 CFR 75, Appendix D and F or the CO_2 emissions CEMS data. The calculated hourly rate is averaged daily.

c. Within 180 days of the date of initial startup of the FD3-series combustion turbine generator, 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 (CTG5) and heat recovery steam generator (HRSG5) into the atmosphere in excess of 0.460 tons CO_2/MWh (net), not including duct burning firing, during the test. To determine this BACT emission limit, Permittee shall calculate the limit based on the measured net hourly energy output (MWh (net)), the CTG is operating above 90% of its design capacity without duct burning 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, and shall not combust any fuel in the CTG until the Permittee has shown compliance with that limit during a subsequent emission test.

d. Upon demonstration that the FD3-series combustion turbine generator is in compliance with the design emissions limit via an emission test, the Permittee shall not discharge or cause the discharge of emissions from the Combustion Turbine Generator (CTG5) and heat recovery steam generator (HRSG5) into the atmosphere in excess of 0.460 ton CO_2/MWh (net) on a 30-day rolling average, and shall not discharge or cause the discharge of emissions into the atmosphere in excess 1,063,650 tons of CO_2e on a 365-day rolling average. To determine this BACT emission limits, the Permittee shall calculate the limit based on the measured net hourly energy output (MWh (net)) and the tons of CO_2 calculated from the equations provided in 40 CFR 75, Appendix D and F or the CO_2 emissions CEMS data. The calculated hourly rate is averaged daily.

e. Modification of the proposed FD2-series combustion turbine generator, identified as CTG5, to the FD3-series combustion turbine generator shall commence within eighteen (18) months of commencement of commercial operation of the initial project, or no later than eighteen (18) months after initial testing is completed. Completion of the initial project will occur the date of the commercial operation of the FD2-series combustion turbine.

f. Within 180 days of the date of initial startup of for both the FD2 and FD3-series combustion turbine generator, the Permittee shall not exceed a Combustion Turbine Generator average net heat rate of 7,730 Btu/kWh (HHV), not including duct burner firing, during the test for combustion turbine unit. To determine this BACT emission limit, Permittee shall calculate the average net heat rate on a hourly basis consistent with equation F-20 and procedures provided in 40 CFR Part 75, Appendix F, § 5.5.2, the measured net hourly heat rate (kWh), that the CTG is operating above 90% of its design capacity without duct burning 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 emissions limit, then the Permittee shall remedy the CTG's failure to meet the emissions limit, and shall not combust any fuel in the CTG until the Permittee has shown compliance with that heat rate limit during a subsequent emission test.

g. Upon initial demonstration that the FD2-series and FD3-series combustion turbine generator complies with the emissions limit via an emission test, the Permittee shall not exceed a Combustion Turbine Generator net heat rate of 7,730 Btu/kWh (HHV) on a 30-day rolling average, for both the FD2- or FD3-series combustion turbine unit. To determine this limit, Permittee shall calculate the average net heat rate on a hourly basis consistent with equation F-20 and procedure provided in 40 CFR Part 75, Appendix F, § 5.5.2 and the measured net hourly energy output (kWh). The calculated hourly heat rate is averaged daily.

h. Permittee shall determine the hourly CO_2 emission rate from 40 CFR Part 75, Appendix G, using F_c factors updated monthly from fuel analysis or, as an alternative, 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).

2. Monitoring of CO_2 Emissions for CTG5/HRSG5

a. The permittee shall determine the CO_2 hourly emission rate and CO_2 mass emissions for the combustion turbine generator and heat recovery steam generator, identified as CTG5/HRSG5, using an O_2 monitor according to appendix F to 40 CFR Subpart 75. In accordance to 40 CFR Subpart 75.20(c)(4), the permittee shall determine hourly CO_2 concentration and mass emissions with a flow monitoring system; a continuous O_2concentration monitor; fuel F and Fc factors; and, where O_2 concentration is measured on a dry basis (or where Equation F–14b in appendix F to 40 CFR Subpart 75 is used to determine CO_2concentration), either, a continuous moisture monitoring system, as specified in §75.11(b)(2), or a fuel-specific default moisture percentage (if applicable), as defined in §75.11(b)(1); and by using the methods and procedures specified in appendix F to 40 CFR Subpart 75.

b. Permittee shall install, calibrate, and operate a fuel flow meter and perform periodic scheduled GCV fuel sampling for the combustion turbine generator and heat recovery steam generator, identified as CTG5/HRSG5, and shall meet the applicable requirements, including certification testing, of 40 CFR Part 75, Appendix D and 40 CFR Part 60 to be used in conjunction with the F_c factor based on the procedures to calculate the CO_2 emission rate in 40 CFR Part 75, Appendix F.

c. Oxygen analyzers shall continuously monitor and record oxygen concentration in the combustion turbine generator and heat recovery steam generator identified as CTG5/HRSG5. It shall reduce the oxygen readings to an averaging period of 6 minutes or less and record it at that frequency.

d. 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., two successive semiannual CGAs may be conducted).

e. As an alternative to Special Condition II.B.2.a, the permittee may install a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions discharged to the atmosphere.

f. In accordance with 40 CFR Part 75, Appendix D and 40 CFR Part 60, the permittee shall ensure that all required fuel flow meter is 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 Part 75, Appendix D and G).

g. 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.

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

3. FD2/FD3 Combustion Turbine Work Practice and Operational Requirements

a. Permittee shall calculate the amount of CO_2 emitted for both the FD2- and FD3-series CTG from combustion in tons per hour (tons/hr) on a 365-day rolling average, and converted to tons per year (tpy) based on equation G-4 of 40 CFR Part 75 and the average net heat rate on an hourly basis based on the heat input calculation procedures contained in 40 CFR Part 75, Appendix F, equation F-20.

b. The calculated CO_2 emissions from Special Condition II.B.3.a shall be compared to the measured CO_2 emissions from the O_2 emission monitor, required in Special Condition II.B.2.a, and if the Permittee is using the CO_2 monitor (CEMS) methodology, then the calculated hourly stack gas volumetric flow rate, required in Special Condition II.B.1, on a daily basis. If the mean difference between the calculated and measured CO_2 emission monitor result is greater than 10% of measured CO_2 concentration, the permittee shall review the emission units and monitoring instrumentation operational performance. From this review, any corrective measures taken are to be identified, recorded, including the reason for the CO_2 emissions difference and corrective measures completed within 48 hours of the corrective measures being taken. If the permittee chooses to install and operate a CO_2 CEMS equipped with a volumetric stack gas monitoring system, then the CO_2 emission calculation from Special Condition II.B.3.a and the mean difference comparison is no longer a requirement, then the permittee shall rely on the data from the CO_2 CEMS for compliance purposes.

c. Permittee shall calculate the CH_4 and N_2O emissions on a 365-day rolling average. Permittee shall determine compliance with the CH_4 and N_2O emissions limits contained in this section 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).

d. Permittee shall calculate the CO_2e emissions on a 365-day rolling average, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1.

e. Fuel for the FD2 or FD3 Combustion Turbines shall be limited to natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf). 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, Permittee shall provide a sample and/or analysis of the fuel-fired in the

Combustion Turbines or shall allow a sample to be taken by EPA for analysis.

f. The flow rate of the fuel combusted in combustion turbine emission unit, identified as CTG5, shall be measured and recorded using an operational non-resettable elapsed flow meter.

g. Permittee shall measure and record the new energy output (MWh (net)) on an hourly basis.

h. On or before the date of initial performance test required by 40 CFR 60.8, and thereafter, Permittee shall install, and continuously operate, and maintain the HRSG5 equipped with a SCR so emissions are at or below the emissions limits specified in this permit and TCEQ permit No. 45642/PSD-TX-979M2/N036M2.

i. On or after initial performance testing, permittee shall use the combustion turbine, Heat Recovery Steam Generator, Steam Turbine and Plant-wide energy efficiency processes, work practices and designs as represented in the permit application.

4. Requirements during FD2/FD3 Combustion Turbine (CTG5) 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 of CTG5 is defined as the period that begins when there is measureable fuel flow to the CTG5 and ends when the CTG5 load reaches 60 percent. A startup for each CTG5 is limited to 480 minutes.

ii. A shutdown of each CTG5 is defined as the period that begins when CTG5 load falls below 60 percent and ends when there is no longer measureable fuel flow to CTG5. A shutdown for CTG5 is limited to 180 minutes.

c. 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.

d. During startup and shutdown, CTG5 and HRSG5 emissions shall comply with all provisions of BACT emission limitations in Special Condition II.B.1.

C. Fugitive Emission Sources

1. Fugitive Emission Sources Emission Limits

At all times, including equipment startup and shutdown, Permittee shall not discharge, or cause the discharge of emissions from each unit into the atmosphere, in excess of the following:

Table 3. Fugitive Emission Sources Emission Limits

ID No.	Description	GHG Pollutants			Fugitive Sources Emissions Limit	
		Pollutant	Mass Basis TPY	CO_2e Basis TPY	CO_2e TPY	Total CO_2e TPY
NG-FUG	Fugitive Natural Gas emissions from piping components (including valves & flanges)	CH_4[1]	2.84	59.69	59.69	60
		CO_2	0.11	0.11	0.11	
SF6-FUG	SF_6 Insulated Electrical Equipment	SF_6	0.00018	4.30	4.30	4.30

1. Because the emissions from this unit are calculated to be 94.44% methane (CH_4) from natural gas analysis, the remaining pollutant emissions are not presented in the table.

2. Fugitive Emission Sources Work Practice and Operational Requirements

a. For emission unit NG-FUG, CH_4 emissions shall be calculated annually (calendar year). Permittee shall not exceed 2.84 tons per year of methane (equivalent to 59.69 tons of CO_2) from all piping components including valves and flanges and an overall emissions limit of 60 tons per year of CO_2e. Emissions shall be calculated annually based on the emission factors from Table W-1A of 40 CFR Part 98, Subpart W, Petroleum and Natural Gas Systems using the reduction credit from 28LAER and calculations given in the TCEQ Technical Guidance Document for Equipment Leak Fugitives, dated October 2000.

b. The permittee shall implement an as-observed auditory, visual and olfactory (AVO) method for detecting leaking from natural gas piping components

c. 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 one (1) 72 lb SF_6 circuit breakers with leak detection.

d. 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.

III. Recordkeeping Requirements

A. In order to demonstrate compliance with the GHG emission rates for both the FD2- and FD3-series CTG, 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);
c. Record the number and duration of start-ups for each engine; and
d. Record the number and duration of shutdowns for each engine.

B. Permittee will maintain site-specific procedures for best/optimum maintenance practices and vendor-recommended operating procedures and O&M manuals. These manuals must be maintained with the permit and located onsite.

C. Permittee shall maintain records that include the following: the occurrence and duration of any startup, shutdown, or malfunction, performance testing, calibrations, checks, GHG emission units and CO_2 emission CEMS maintenance (if a CO_2 CEMS is present), duration of any periods during which a monitoring device is inoperative, and corresponding emission measurements.

D. Permittee shall maintain records for five (5) years from the date of any of the following: the duration of startup, shutdown, the initial startup period as defined in Section IV for the emission units, pollution control units and CEMS (if a CO_2 CEMS is present), malfunctions, performance testing, calibrations, checks, maintenance and duration of an inoperative monitoring device and emission units with the required corresponding emission data.

E. Permittee shall maintain records of all GHG emission units and CO_2 emission CEMS certification tests (if a CO_2 CEMS is present) and monitoring and compliance information required by this permit.

F. Permittee will implement the AVO program and keep records of the monitoring results, as well as the repair and maintenance records.

G. At least once per year, the permittee will obtain an updated analysis of the inlet gas to document the CO_2 and methane content of the gas streams.

H. Permittee shall maintain records and submit a written report of all 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 thirtieth (30th) day following the end of each semi-annual period and shall include the following:

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

2. Applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time);

3. 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;

4. Any failure to conduct any required source testing, monitoring, or other compliance activities; and

5. Any violation of limitations on operation, including but not limited to restrictions on hours of operation of the emergency generator or fire pump.

I. Excess emissions shall be defined as any period in which the facility emissions exceed a maximum emission limit set forth in this permit.

J. 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.

K. All records required by this PSD Permit shall be retained for not less than 5 years following the date of such measurements, maintenance, and reports.

IV. Shakedown Periods

The combustion turbine emission limits and requirements in conditions II.A and II.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.

V. Performance Testing Requirements:

A. Upon completion of the first phase of construction, the holder of this permit shall perform an initial stack test for the FD2-series combustion turbine to establish the actual quantities of air contaminants being emitted into the atmosphere from emission unit CTG5/HRSG5 and 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 for the CTGs.

B. Upon completion of the second phase of construction, the holder of this permit shall perform an initial stack test for the FD3 series combustion turbine to establish the actual quantities of air contaminants being emitted into the atmosphere from emission unit CTG5/HRSG5 and 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 for the CTGs.

C. Within sixty (60) days after achieving the maximum production rate at which the F2-series CTG will be operated, but not later than one hundred and eighty (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 the EPA. Additional sampling may be required by TCEQ or EPA.

D. Within sixty (60) days after achieving the maximum production rate at which the FD-3 series CTG will be operated, but not later than one hundred and eighty (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 the EPA. Additional sampling may be required by TCEQ or EPA.

E. Permittee shall submit a performance test protocol to EPA no later than thirty (30) days prior to the test to allow review of the test plan and to arrange for an observer to be present at the test for both the FD2- and FD3-series combustion turbine generator. The performance test shall be conducted in accordance with the submitted protocol, and any changes required by EPA.

F. The holder of this permit shall perform stack sampling and other testing as required to establish the actual quantities of CO_2 emissions being emitted into the atmosphere from emission unit CTG5/HRSG5 and to determine the initial compliance with all emission limits established in this permit for both the FD2- and FD3-series CTG. Sampling shall be conducted in accordance with EPA Methods 1-4 and 3b for the concentration of CO_2 for the CTGs.

G. Fuel sampling for emission unit CTG5/HRSG5 shall be conducted in accordance with 40 CFR Part 75 and Part 98.

H. The turbine shall be tested at or above ninety percent (90%) of maximum load operations for the atmospheric conditions which exist during testing. The duct burners shall be tested at its maximum firing rate 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 at the pretest meeting the manner in which stack sampling will be executed in order to demonstrate compliance with the emissions limits contained in Section II and the emission standards found in NSPS, Subpart KKKK.

I. 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 will be sampled and analyzed while at a the minimum load include (but not limited to) VOC and O_2.

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

K. The owner or operator must provide the EPA at least thirty (30) days' prior notice of any performance test, except as specified under other subparts, to afford the EPA the opportunity to have an observer present and/or to attend a pre-test meeting. If there is a delay in the original test date, the facility must provide at least seven (7) days prior notice of the rescheduled date of the performance test.

L. 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.

M. 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.

VI. Agency Notifications

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

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