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-1244-GHG
PERMITTEE:	Lower Colorado River Authority (LCRA) P.O. Box 220 Austin, TX 78767-0220
FACILITY NAME:	Lower Colorado River Authority (LCRA) Thomas C. Ferguson Power Plant
FACILITY LOCATION:	2001 Ferguson Road Horseshoe Bay, TX 78657

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 and published at 76 FR 25178),the U.S. Environmental Protection Agency, Region 6 is issuing a *Prevention of Significant Deterioration* (PSD) permit to the Lower Colorado River Authority (LCRA) for Greenhouse Gas (GHG) emissions. The Permit applies to the construction of a new approximately 590 megawatt (MW) natural gas-fired combined-cycle power plant to replace the existing power generation at the existing facility located in Horseshoe Bay, Texas.

LCRA is authorized to construct the LCRA, Thomas C. Ferguson power 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. PSDTX1244. 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 LCRA 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.

11/10/11

Carl E. Edlund, Director
Multimedia Planning and Permitting Division

Date

LCRA, Thomas C. Ferguson Power Plant (PSD-TX-1244-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 Thomas C. Ferguson power plant in Llano County, Texas. With this construction permit, LCRA will replace the existing 37 year-old 440 MW steam boiler with two new natural gas-fired combined-cycle combustion turbine units with a generating capacity of approximately 590 MW. The steam produced from the two new combustion turbines will exhaust to two dedicated Heat Recovery Steam Generators (HRSG) to produce steam. The steam produced from the two HRSGs is routed to the new shared steam turbine unit to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid.

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

Emission Unit Id. No.	Description
U1-STK and U2-STK	2 Natural Gas-Fired General Electric 7FA Combustion Turbines. Each unit is rated at a maximum base-load electric output of approximately 195 MW each and vented to a dedicated Heat Recovery Steam Generator (HRSG) that is equipped with a Selective Catalytic Reduction (SCR) and an Oxidation Catalyst (OC).
NG-FUG	Fugitive Natural Gas emissions from piping components
EMGEN1-STK	1340 – horsepower (hp) Diesel Fired Emergency Generator rated at 93.8 MMBtu/hr and limited to 100 hours of operation per year for non-emergency activities.
FWP1-STK	617 – horsepower (hp) Diesel Fired Fire Water Pump rated at 43.2 MMBtu/hr and limited to 100 hours of operation per year for non-emergency activities.
SF6-FUG	SF_6 Insulated Electrical Equipment (i.e., circuit breakers) consisting of two new 24 lb SF_6 insulated circuit breakers, six new 58 lb SF_6 circuit breakers and 4 existing 58 lb SF_6 insulated circuit breakers.

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; or

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

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

4. EPA may extend the 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 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;

3. date upon which initial performance tests will commence, in accordance with the provisions of Section V, 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 V.B; and

4. date upon which certification tests of the CO_2 continuous emission monitoring system (CEMS) will commence 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.

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 two working days 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. In addition, Permittee shall notify EPA in writing within 15 days of any such failure described under Section III. This notification shall include 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 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 and operate this project in compliance with this PSD Permit, the application on which this permit is based, the TCEQ PSD Permit No. PSDTX1244, 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

BACT	Best Available Control Technology
CAA	Clean Air Act
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
DCS	Distributed Control System
dscf	Dry Standard Cubic Foot
EPN	Emission Point Number
ERCOT	Electric Reliability Council of Texas
FR	Federal Register
GHG	Greenhouse Gas
gr	Grains
HHV	High Heating Value
hp	Horsepower
hr	Hour
HRSG	Heat Recovery Steam Generator
kwh	Kilowatt-hour
lb	Pound
LCRA	Lower Colorado River Authority
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-hr
N_2O	Nitrous Oxides
NSPS	New Source Performance Standards
OC	Oxidation Catalyst
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

II. SPECIAL PERMIT CONDITIONS

A. Facility Emission Limits

Short term emissions, in pounds per hour (lb/hr) on a 30-day basis, annual emissions, in tons per year (TPY) on a 365-day rolling average basis shall not exceed the following:

Table 1. Facility Emission Limits

ID No.	Description	GHG Mass Basis			CO$_2$e		
			lb/hr[1]	TPY[2,3]		lb/hr[1]	TPY CO$_2$e[2,3]
U1-STK	Unit 1 of 2 Natural Gas Fired General Electric 7FA Combustion Turbines	CO_2		908,957.6	CO_2		908,957.6
		CH_4		16.8	CH_4		353.3
		N_20		1.7	N_20		521.6
U2-STK	Unit 2 of 2 Natural Gas Fired General Electric 7FA Combustion Turbines	CO_2		908,957.6	CO_2		908,957.6
		CH_4		16.8	CH_4		353.3
		N_20		1.7	N_20		521.6
NG-FUG	Fugitive Natural Gas emissions from piping components	CH_4[4]		16.2			327.2
EMGEN1-STK	1,340-hp Diesel Fired Emergency Generator	CO_2[5,6]	15,263.2[1]	763.2		15,314.0[1]	765.7
FWP1-STK	617-hp Diesel Fired Fire Water Pump	CO_2[5,6]	7,027.8[1]	351.4		7,052.0[1]	352.6
SF6-FUG	SF_6 Insulated Electrical Equipment	SF_6		0.006			131.0
Totals		**CO_2**		**1,819,029.8**	**CO_2e**		**1,821,241.5**
		CH_4		**49.8**			
		N_20		**3.4**			
		SF_6		**0.006**			

1. Compliance with the short term emission limits (pounds per hour) 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.
6. Hours of operation for emission units EMGEN1-STK and FWP1-STK shall not exceed 100 hours of non-emergency only operation per year.

B. Requirements for Combustion Turbine

1. Combustion Turbine Generator (CTG) BACT Emission Limits

a. On or after the date of initial startup, Permittee shall not discharge or cause the discharge of emissions from the two Combustion Turbine Units (U1-STK and U2-STK) and steam turbine generator into the atmosphere in excess of 0.459 ton CO_2/MWh(net) on a 365-day rolling average. To determine this BACT emission limit, 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 Appendix G or the CO_2 emissions CEMS data. The calculated hourly rate is averaged daily.

b. Permittee shall not exceed an average net heat rate of 7720 Btu/kwh (HHV) on a 365-day rolling average from the Combustion Turbine Units (U1-STK and U2-STK) and steam turbine generator. 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.

c. Permittee shall determine the hourly stack gas volumetric flow 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. CO_2 Emission Monitor or CO_2 Continuous Emissions Monitoring System (CEMS) for U1-STK and U2-STK

a. Permittee shall install, calibrate, and operate a CO_2 emission monitor for each emission unit, U1-STK and U2-STK, and shall meet the applicable requirements, including certification testing, of 40 CFR Parts 60 and 75 to be used in conjunction with the F_c factor based on the procedures to calculate the volumetric stack gas flow rate in 40 CFR Part 75, Appendix F.

b. As an alternative to Special Condition II.B.2.a., 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.

c. In accordance with 40 CFR § 75.4(b), permittee shall ensure that all required CO_2 monitoring system/equipment are installed 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. Permittee shall ensure compliance with the specifications and test procedures for CO_2 emission monitoring system at stationary sources, 40 CFR Part 75.

e. Permittee shall meet the appropriate quality assurance requirements specified in 40 CFR Part 60, Appendix F for the CO_2 emission monitoring system.

3. Combustion Turbine Work Practice and Operational Requirements

a. Permittee shall calculate the amount of CO_2 emitted from combustion in tons/hr, averaged daily and converted to 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 CO_2 emission monitor, required in Special Condition II.B.2.a, and the calculated hourly stack gas volumetric flow rate, required in Special Condition II.B.1.c., 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, permittee shall review the emission units and monitoring instrumentation operational performance. From this review, any corrective measures taken are to be identified and recorded, and the recorded information shall include 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.3a and mean difference comparison is no longer a requirement and 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 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 emission units U1-STK and U2-STK 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 HRSG equipped with a SCR and Oxidation Catalyst so emissions are at or below the emissions limits specified in this permit and TCEQ permit No. PSDTX1244.

i. The existing Unit Number 1 natural gas-fired utility boiler (EPN Stack 1) shall be dismantled and permanently shutdown. To document the creditable reduction for the permanent shutdown of the boiler, permittee shall notify EPA by letter of the dismantling activities within 15 days of the permanent shutdown of the existing 440 MW boiler.

j. 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 Combustion Turbine (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 of each CTG (U1-STK and U2-STK) is defined as the period that begins when there is measureable fuel flow to the CTG and ends when the CTG load reaches 50 percent. A startup for each CTG is limited to six hours.

ii. A shutdown of each CTG (U1-STK and U2-STK) is defined as the period that begins when the CTG load falls below 50 percent and ends when there is no longer measureable fuel flow to the CTG. A shutdown for each CTG is limited to two hours.

c. During startup and shutdown, emissions from each unit and associated equipment shall not exceed the following:

Table 2. Startup and Shutdown Emissions

ID No.	Description	Pollutant	Startup and Shutdown GHG Mass Basis[1]	Startup and Shutdown CO_{2e}
			lb/hr	lb/hr
U1-STK	Unit 1 of 2 Natural Gas Fired Combustion Turbine	CO_2	153,392.10	153,392.10
		CH_4	2.84	353.30
		N_2O	0.28	521.60
U2-STK	Unit 2 of 2 Natural Gas Fired Combustion Turbine	CO_2	153,392.10	153,392.10
		CH_4	2.84	353.30
		N_2O	0.28	521.60

[1] Startup and Shutdown lb/hr emissions are an estimate and are enforceable through compliance with the applicable special condition(s) such as Special Condition II.B.4.e and other permit application representations, such as fuel gas preheating and boiler feed pump fluid drives.

d. Permittee must record the time, date, fuel heat input (HHV) in mmBtu/hr and duration of each startup and shutdown event. The records must include hourly CO_2 emission levels as measured by the CO_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, N_2O, and CH_4 emissions during each startup and shutdown event based on the equations represented in the permit application and Special Conditions II.B.4. These records must be kept for five years following the date of such event.

e. During startup and trip conditions, Permittee shall utilize the steam turbine bypass system to direct the steam being generated in the HRSG to the condenser as needed to complete all startup operations within 6 hours.

f. During startup and shutdown, the CTG and HRSG emissions shall comply with all provisions of BACT emission limitations in Special Condition II.B.1 and Special Conditions II.B.4, including the emissions in the Table 2 above. The SCR system, including ammonia injection, shall be operated in a manner to minimize emissions, as technologically feasible, and not later than when the load reaches 50% of the plant net output.

C. Requirements for Auxiliary Combustion Equipment

1. Auxiliary Combustion Equipment 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. Auxiliary Combustion Equipment Emission Limits

ID No.	Description	GHG Pollutants Mass Basis[1]		
			lbs/hr	TPY
FWP1-STK	617- hp (not to exceed) Diesel Fired Fire Water Pump	GHG mass basis	7,027.80	351.40
EMGEN 1-STK	1,340- hp (not to exceed) Diesel Fired Emergency Generator	GHG mass basis	15,263.20	763.10

[1] Because the emissions from this unit are calculated to be over 99.9% carbon dioxide (CO_2), the remaining pollutant emissions are not presented in the table.

2. Auxiliary Combustion Equipment Work Practice and Operational Requirements

a. The Diesel Fired Fire Water Pump (FWP1-STK) and Diesel Fired 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 (FWP-STK and EMGEN1-STK) or shall allow a sample to be taken by EPA for analysis to demonstrate the percent sulfur of the fuel.

b. The Diesel Fired Fire Water Pump (FWP1-STK) and Diesel Fired Emergency Generator (EMGEN1-STK) are limited to 100 hours of non-emergency operation per year for each unit and a heat input value of 43.2 MMBtu/hr and 93.8 MMBtu/hr for the Diesel Fired Fire Water Pump and the Diesel Fired Emergency Generator, respectively.

c. The Diesel Fired Fire Water Pump (FWP1-STK) and Diesel Fired Emergency Generator (EMGEN1-STK) shall meet the monitoring and recordkeeping requirements as required in 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

d. Permittee shall install and maintain an operational non-resettable elapsed time meter for the Diesel Fired Fire Water Pump (FWP1-STK) and Diesel Fired Emergency Generator (EMGEN1-STK).

e. Permittee shall maintain a file of all records, data measurements, reports and documents related to the operation of the Diesel Fired Fire Water Pump (FWP1-STK) and Diesel Fired Emergency Generator (EMGEN1-STK), 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 II.C.2.a, fuel heat input values required in Special Condition II.C.2.b, hours of operation; 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. 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 4. Fugitive Emission Sources Emission Limits

ID No.	Description	GHG Pollutants Mass Basis	
		Pollutant	TPY
NG-FUG	Fugitive Natural Gas emissions from piping components	CH_4[1]	16.20
SF6-FUG	SF_6 Insulated Electrical Equipment	SF_6	0.006

1. Because the emissions from this unit are calculated to be 96% methane (CH_4), 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 520 gas/vapor valves, 1460 gas/vapor flanges and 3 gas/vapor compressors. 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.

b. 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 2 new 24 lb and 6 new 58 lb enclosed-pressure SF_6 circuit breakers with leak detection and 4 existing 58 lb SF_6 insulated circuit breakers.

c. 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. Permittee shall maintain a file of 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; all records relating to performance tests and monitoring of auxiliary combustion equipment; for each diesel fuel oil delivery, documents from the fuel supplier certifying compliance with conditions II.C.2.a and II.C.2.b; 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.

B. 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, duration of any periods during which a monitoring device is inoperative, and corresponding emission measurements.

C. Permittee shall maintain records for 5 years from the event that includes the duration of startup, shutdown, the initial shakedown period for the emission units, pollution control units and CEMS, malfunctions, performance testing, calibrations, checks, maintenance and duration of an inoperative monitoring device and emission units with the required corresponding emission data.

D. Permittee shall maintain records of all GHG emission units and CO_2 emission CEMS certification tests and monitoring and compliance information required by this permit.

E. 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 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.

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

G. 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.

H. 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. The holder of this permit shall perform an initial stack test to establish the actual quantities of air contaminants being emitted into the atmosphere from emission units U1-STK and U2-STK 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. 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 the 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 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 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 units U1-STK and U2-STK and to determine the initial compliance with all emission limits established in this permit. Sampling shall be conducted in accordance with EPA Methods 1-4 and 3b for the concentration of CO_2 for the CTGs.

E. Fuel sampling for emission units U1-STK and U2-STK shall be conducted in accordance with 40 CFR Part 75 and Part 98.

F. Each turbine shall be tested at or above 90% of maximum load operations, below 90% of maximum load operations but above 60% and below 60% but above 45% load operations. Each 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.

G. 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.

H. The owner or operator must provide the EPA at least 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 7 days prior notice of the rescheduled date of the performance test.

I. 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.

J. 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:

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