**Special Conditions**

Permit Numbers 1467, PSDTX1090M1, GHGPSDTX199, and N284

Emission Standards, Fuel Specifications and Work Practices

1. This permit covers only those sources of emissions listed in the attached table entitled "Emission Sources - Maximum Allowable Emission Rates" (MAERT), and those sources are limited to the emission limits and other conditions specified in the attached table. The annual rates are based on any consecutive 12-month period.
2. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on Standards of Performance for New Stationary Sources. The following subparts of Title 40 Code of Federal Regulations (40 CFR) Part 60 apply:
   1. General Conditions, Subpart A
   2. Unit 4 (Emission Point Numbers (EPNs) S4-1 and S4-2) is subject to the applicable requirements of Subpart GG, Standards of Performance for Stationary Gas Turbines and Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units for Which Construction Is Commenced After June 19, 1984.
   3. Unit 6 (EPNs SC-S6A, SC-S6B, CC-S6A and CC-S6B) is subject to the applicable requirements of Subpart GG, Standards of Performance for Stationary Gas Turbines. Unit 6 (EPNs CC-S6A and CC-S6B) is subject to the applicable requirements of Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978.
   4. EPN Fire-2 is subject to applicable requirements of Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. **(xx/20)**
   5. Unit 7 (EPN SC-7) is subject to the requirements of Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, and TTTT, Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units. **(xx/20)**
3. These facilities shall comply with all applicable requirements of the EPA regulations on National Emission Standards for Hazardous Air Pollutants. The following subparts of 40 CFR Part 63 apply: **(xx/20)**
   1. General Provisions, Subpart A
   2. National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, Subpart YYYY
   3. National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, Subpart ZZZZ
   4. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, Subpart DDDDD
4. NOx Control Methods:
   1. Water injection shall be used as needed to reduce the emissions of nitrogen oxides (NOx) from each of the turbines in Unit 4, EPNs S4-1 and S4-2. The water injection rate shall be sufficient to meet the limitations in the MAERT.
   2. Dry low-NOx combustors shall be used to reduce the emissions of NOx from both of the turbines in Unit 6, EPNs SC-S6A and SC-S6B, while operating in simple cycle mode. Selective Catalytic Reduction with ammonia (NH3) injection will be used for NOx reduction from the heat recovery steam generators (HRSGs) while operating the turbines or duct burners (EPNs CC-S6A and CC-S6B) in the combined cycle mode during High Load Operations, as described in Special Condition No. 7. Dry low-NOx combustors and SCR shall be used to reduce the emission NOx from the turbine in Unit 7 (EPN SC-7). Ammonia injection shall be sufficient to meet the NOx emission limits in the MAERT. **(xx/20)**
   3. For Unit 6 (EPNs CC-S6A and CC-S6B) and Unit 7 (EPN SC-7), the inlet temperature to the selective catalytic reduction (SCR) unit shall be monitored, as provided by the SCR manufacturer, to identify those periods of time when the inlet gas temperature is in the operating range for ammonia injection. **(xx/20)**
5. Fuel ----Sulfur Content Requirements:
   1. Fuel fired in the gas turbines and duct burners for Unit 4 shall be natural gas with a sulfur content less than or equal to 0.25 grain of hydrogen sulfide and five grains of total sulfur per 100 dry standard cubic feet.
   2. For Unit 6, the annual average sulfur content shall be less than or equal to 1.2 grains of total sulfur per 100 dry standard cubic foot.
   3. Fuel Fired in the Turbine for Unit 7 shall limited to natural gas with a Sulfur content not exceed 5 grains per 100 scf on an hourly basis and 1gr/scf on an annual basis. **(xx/20)**
   4. The line heater (EPN LH-1) is limited to firing no more than 3.9 million British units per hour (MMBtu/hr). **(xx/20)**
   5. The emergency fire water pump engine (EPN FIRE-2) must use diesel fuel containing no more than 0.0015 percent (%) sulfur by weight. **(xx/20)**
   6. The permit holder shall monitor fuel consumption continuously for each turbine unit using a monitoring device that is accurate to ±5% and maintained, calibrated, and operated in accordance with the manufacturer’s specifications. The certification of the monitoring device shall be in accordance with EPA approved methods and calibrated in accordance with the manufacturer’s recommendations or at least annually. The permit holder shall monitor fuel consumption continuously for the following four combinations of combustion units:
      1. Unit 4 (GT-1) Gas Turbine including the duct burner
      2. Unit 4 (GT-2) Gas Turbine including the duct burner
      3. Unit 6 (GT-6A) Gas Turbine including duct burner DB-6A
      4. Unit 6 (GT-6B) Gas Turbine including duct burner DB-6B
   7. Emissions of sulfur dioxide (SO2) shall be monitored in accordance with 40 CFR Part 75.11(e)(1) to demonstrate compliance with the maximum allowable emission rates for SO2.
6. Cooling Tower Chlorine System Inspections:
   1. Audio, olfactory, and visual inspection for chlorine leaks at Cooling Towers 4 and 6 shall be performed once per week.
   2. Upon detection of a leak, plant personnel shall initiate actions to commence repair or replacement of the leaking component.
   3. Date and time of each inspection shall be noted in the operator’s log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the Texas Commission on Environmental Quality (TCEQ) or any other agency with jurisdiction upon request.

Emission Concentration Limitations

1. For Unit 6 (EPNs SC-S6A and SC-S6B and EPNs CC-S6A and CC-S6B):
   1. The 24-hour daily-block average concentration in the stack gases for the Unit 6 combustion turbines (EPNs SC-S6A and SC-S6B) shall not exceed 9 parts per million dry (ppmvd) for NOX, when operating at High Load in the simple cycle mode, or 3 ppmvd when operating in Steady State, High Load combined cycle mode, corrected to 15 percent oxygen (O2).
      1. High Load Operations are defined as each 1-hour block when the combustion turbine operates for the entire 1-hour block in "Pre-mix" mode, as indicated by the General Electric Turbine Control System, at greater than 65% load. High Load Operations do not include periods of startup, shutdown, or operations below 65% load.
      2. Low Load Operations, defined as periods of startup, shutdown, and operation outside of pre-mix mode or less than or equal to 65% load are authorized, provided the emission rates specified by Special Condition No. 1 are not exceeded.
      3. Steady State does not include periods of operation where the load changes 10% or more at any time within any hour or any two consecutive hours.
   2. Total Low Load Operation hours shall not exceed 2,500 hours per turbine per year.
   3. The NOx concentration, measured by the continuous emission monitoring system (CEMS), shall be corrected to 15 percent O2.
2. Concentrations of NH3 in the SCR stack shall not exceed 15 parts per million (ppm) on a three hour basis or 10 ppm on an annual average basis, corrected to 15 percent O2.
3. Opacity from Units 4 and 6 are limited as follows:
   1. For Unit 4 (EPNs S4-1 and S4-2), opacity of emissions from each stack shall not exceed 20 percent averaged over a six-minute period. Each determination shall be made by first observing for visible emissions while each facility is in operation. Observations shall be made at least 15 feet and no more than 0.25 mile from the emission point. If visible emissions are observed from an emission point, then the opacity shall be determined and documented within 24 hours for that emission point using 40 CFR Part 60, Appendix A, Test Method 9. Contributions from uncombined water shall not be included in determining compliance with this condition. Observations shall be performed and recorded quarterly. If the opacity exceeds 20 percent, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation.
   2. For Unit 6 (EPNs SC-S6A & B and CC-S6A & B), opacity of emissions from each stack shall not exceed 5 percent averaged over a six-minute period, except during Low Load Operations. During Low Load Operations, the opacity shall not exceed 15 percent averaged over a six-minute period. Each determination shall be made by first observing for visible emissions while each facility is in operation. Observations shall be made at least 15 feet and no more than 0.25 mile from the emission point. If visible emissions are observed from an emission point, then the opacity shall be determined and documented within 24 hours for that emission point using 40 CFR Part 60, Appendix A, Test Method 9. Contributions from uncombined water shall not be included in determining compliance with this condition. Observations shall be performed and recorded quarterly. If the opacity exceeds 5 percent during High Load Operations, or 15 percent during Low Load Operations, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation.
   3. For Unit 7 (EPN-7), opacity of emissions from the stack shall not exceed 5% averaged over a six-minute period. During periods of planned MSS, the opacity shall not exceed 15% averaged over a six-minute period. This determination shall be made by first observing for visible emissions while the facility is operating. A certified opacity reader is not required for this initial observation to determine whether visible emissions are present. Observations shall be made at least 15 feet and no more than 0.25 mile from the emission point. If visible emissions are observed from the stack, then opacity shall be determined by 40 CFR Part 60, Appendix A, Test Method 9. The opacity test must be performed by a certified opacity reader. Contributions from uncombined water shall not be included in determining compliance with this condition. **(xx/20)**
   4. Observations of Unit 7 shall be performed and recorded once each calendar quarter for each quarter the combustion turbine operates. If the opacity exceeds the six-minute average opacity limits specified above, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation. **(xx/20)**
4. The Diesel Fired Firewater Pump (EPN FIRE) is authorized to fire diesel fuel containing no more than 0.05 weight percent sulfur and is limited to a maximum of 200 non‑emergency hours of operation annually. The diesel firewater pump (EPN FIRE-2) is authorized to fire diesel fuel containing no more than 0.0015 percent (%) sulfur by weight and shall be limited to a maximum of 100 non-emergency hours of operation on a rolling 12-month basis. Each engine shall be equipped with a non-resettable runtime meter. **(xx/20)**
5. The requirements of Pollution Control Project Standard Permit Registration No. 114528, including, but not limited to, emissions limits, monitoring, and recordkeeping, are incorporated by reference.
6. A copy of the current version of this permit shall be kept at the plant site and made immediately available at the request of personnel from the TCEQ, EPA, or any local air pollution control agency having jurisdiction. In addition, the holder of this permit shall clearly identify all equipment at the property that has the potential of emitting air contaminants. Permitted emission points shall be clearly identified corresponding to the emission point numbering on the MAERT.

Initial Determination of Compliance for Unit 7 (xx/20)

1. Sampling ports and platforms shall be incorporated into the design of the exhaust stacks identified as EPN SC-7, according to the specifications set forth in the attachment entitled “Chapter 2, Stack Sampling Facilities.” Alternate sampling facility designs may be submitted for approval by the TCEQ Regional Director.
2. The holder of this permit shall perform stack sampling and other testing to establish the actual quantities of air contaminants being emitted into the atmosphere from EPN SC-7. Unless otherwise specified in this special condition, the sampling and testing shall be conducted in accordance with the methods and procedures specified in Special Condition No. 14F. The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense. The TCEQ Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling.
   1. Air contaminants and diluents from the EPN SC-7 to be sampled and analyzed include (but are not limited to) NOx, CO, volatile organic compounds (VOC), sulfur dioxide (SO2), opacity, O2, and particulate matter (PM) (filterable plus condensable fractions).
   2. EPN SC-7 shall be tested at the maximum load for the atmospheric conditions which exist during testing. CT generator load shall be identified in the sampling report.
   3. Fuel sampling using the methods and procedures of 40 CFR § 60.4415 may be conducted in lieu of stack sampling for SO2. If fuel sampling is used, then compliance with the 40 CFR Part 60, Subpart KKKK, SO2 limits shall be based on 100% conversion of the sulfur in the fuel to SO2.
   4. Requests to waive testing for any air contaminant specified in this condition shall be submitted to the TCEQ Air Permits Division. Test waivers and alternate or equivalent procedure proposals for testing which must have EPA approval shall be submitted to the TCEQ Air Permits Division.
   5. Sampling as required by this condition shall occur within 60 days after achieving the maximum production but no later than 180 days after initial startup of each unit. Additional sampling shall occur as may be required by the TCEQ or Environmental Protection Agency (EPA).
   6. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ “Sampling Procedures Manual” and EPA Test Methods in 40 CFR Part 60, Appendix A.
   7. The TCEQ Regional Office shall be given notice as soon as testing is scheduled but not less than 30 days prior to sampling to schedule a pretest meeting.
      1. The notice shall include:
         * 1. Date for pretest meeting.
         1. Date sampling will occur.
         2. Name of firm conducting sampling.
         3. Type of sampling equipment to be used.
         4. Methods and procedures to be used in sampling, including methods to demonstrate compliance with emission standards found in 40 CFR Part 60, Subpart KKKK.
         5. Procedure used to determine turbine loads during the sampling period.
      2. The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for submitting the test reports.
      3. Prior to the pretest meeting, a written proposed description of any deviation from sampling procedures specified in permit conditions or TCEQ or EPA sampling procedures shall be made available to the TCEQ. The TCEQ Regional Director shall approve or disapprove of any deviation from specified sampling procedures.
   8. Copies of the final sampling report shall be distributed to the TCEQ and EPA within 60 days after sampling is completed. Sampling report format shall comply with Chapter 14 of the TCEQ “Sampling Procedures Manual.” The reports shall be distributed as follows:

One copy to the EPA Region 6 Office, Dallas.

One copy to the TCEQ Regional Office.

Initial Determination of Compliance for Unit 6

1. Both turbines within Unit 6 shall be tested at a low and high load of the permitted operating range that is defined in Special Condition No. 7 for the atmospheric conditions which exist during testing in compliance with applicable portions of 40 CFR Part 60. The duct burners shall be tested at their maximum firing rate while the turbine is operating as close to maximum load as possible. Each tested turbine load shall be identified in the sampling report. The permit holder shall present, at the pretest meeting, the manner in which emission source stack sampling will be conducted in order to demonstrate compliance with emission standards found in 40 CFR Part 60, Subparts A, Da and GG. Sampling must be conducted in accordance with procedures of the TCEQ Sampling Procedures Manual and in accordance with the methods specified in the applicable portions of 40 CFR Part 60. If fuel sampling is used to demonstrate compliance with the maximum allowable emission rates of SO2 in Special Condition No. 1, it shall be based on 100 percent conversion of the sulfur in the fuel to SO2. The holder of this permit is responsible for providing safe and adequate sampling and testing facilities and conducting the sampling and testing operation at the applicant's expense.
   1. Testing of the turbines in simple cycle mode (EPNs SC-S6A and B) and the turbines and duct burners in combined cycle mode (EPNs CC-S6A and B) may be accomplished at different times during the continuous construction schedule.

The TCEQ El Paso Regional Office shall be contacted as soon as any required testing is scheduled but not less than 45 days prior to sampling to schedule a pretest meeting. The notice shall include:

* + 1. Date for pretest meeting.
    2. Date sampling will occur.
    3. Name of firm conducting sampling.
    4. Type of sampling equipment to be used.
    5. Method or procedure to be used in sampling.
    6. Method for determining turbine load.

The purpose of the pretest meeting is to review and formalize the necessary sampling and testing procedures, to review the safety and adequacy of the sampling facilities, to provide the proper data forms for recording pertinent data, to identify each operating parameter which is significant to maintaining emission compliance, and to review the format procedures for submitting the test reports.

A written proposed description of any deviation from sampling procedures specified in this permit condition or any TCEQ or EPA sampling procedure shall be made available to the TCEQ at or prior to the pretest meeting. The TCEQ Regional Director shall approve or disapprove of any deviation from specified sampling procedures. Requests to waive testing for any pollutant specified in Paragraph B of this condition shall be submitted to the TCEQ Air Permits Division in Austin. Test waivers and alternate or equivalent procedure proposals for New Source Performance Standard testing which must have the EPA approval shall be submitted to the TCEQ Air Permits Division in Austin.

* 1. At least one turbine from Unit 6 shall be tested for VOC, PM10, SO2 and H2SO4. Testing for these air contaminants shall be performed concurrently and while operating as close to maximum load as possible for the atmospheric conditions occurring during the test. Ammonia need not be sampled until startup of the duct burners. This testing will be used to demonstrate initial compliance with Special Condition Nos. 1 and 7.
  2. For VOC, PM10, SO2 and H2SO4, if the sampling of one turbine per unit demonstrates compliance, this sampling shall be deemed sufficient to represent emission rates from similar turbines within that unit operating under the same conditions. If the turbine tested exceeds any applicable emission limit of this permit then the other shall be tested for the pollutants which exceeded their respective limits. Additional sampling shall occur as may be required by the TCEQ.
  3. Within 60 days after the completion of the testing and sampling required herein, copies of the sampling report shall be distributed as follows:
     1. One copy to the TCEQ El Paso Regional Office.
     2. One copy to EPA Region 6 in Dallas.
  4. Deadlines for testing and reporting may be extended upon showing of good cause to the TCEQ El Paso Regional Office.

Continuous Demonstration of Compliance for Unit 7 (xx/20)

1. For the turbine stack in EPN SC-7 the holder of this permit shall install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NOX, CO and diluent gases [O2 or carbon dioxide (CO2)].
   1. The CEMS noted above shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B, or an acceptable alternative. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TCEQ Air Permits Division for requirements to be met. The CEMS shall meet the applicable quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1, or an acceptable alternative.
   2. The monitoring concentration data shall be reduced to hourly average values at least once every day, using a minimum of four equally-spaced data points from each one hour period. At least two valid data points shall be generated during the hourly period in which zero and span is performed.
   3. All monitoring data and quality-assurance data shall be maintained by the source for a period of five years and shall be made available to the TCEQ Executive Director or designated representative upon request.
   4. The TCEQ El Paso Regional Office shall be notified at least 21 days prior to any required relative accuracy test audit in order to provide that office the opportunity to observe the testing.
   5. If applicable, the CEMS for the turbines/duct burner stacks may be required to meet the design and performance specifications, pass the field tests, and meet the installation requirements and data analysis and reporting requirements specified in the applicable performance specifications in 40 CFR Part 75, Appendix A. The requirements of 40 CFR Part 75, Appendix A and B, respectively, are deemed an acceptable alternative to the performance specifications and quality assurance requirements of 40 CFR Part 60 for the NOx and O2 or CO2 CEMS.
2. The holder of this permit shall calculate hourly mass emissions in pounds per hour (lb/hr) using the EPA Reference Method 19 or a measured exhaust flow rate and the measured concentrations of NOx and CO from the CEMS required in Special Condition No. 14. Emissions shall be calculated and stored in an electronic format in pounds per hour, pounds per month and tons per year (based on any consecutive 12-month period). Records of this information shall also be available in a form suitable for inspection.
3. The NH3 concentration EPN SC-7 shall be tested or calculated according to one of the methods listed below and shall be tested or calculated according to frequency listed below. Testing for NH3 slip is only required when the SCR unit is in operation.
   1. The holder of this permit may install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NH3. The NH3 concentrations shall be corrected and reported in accordance with Special Condition No. 8.
   2. As an approved alternative, the NH3 slip may be measured using a sorbent or stain tube device specific for NH3 measurement in the 2 to 30 ppm range. The frequency of sorbent or stain tube testing shall be at least one test per day for the first 60 days of operation, after which, the frequency may be reduced to at least one test per week. These results shall be recorded and used to determine compliance with Special Condition No. 8. Test results may consist of the average of three or more measurements.
   3. As an approved alternative to sorbent or stain tube testing or an NH3 CEMS, the permit holder may install and operate a second NOx CEMS probe located between the duct burners and the SCR, upstream of the stack NOx CEMS, which may be used in association with the SCR efficiency and NH3 injection rate to estimate NH3 slip. This condition shall not be construed to set a minimum NOx reduction efficiency on the SCR unit. These results shall be recorded and used to determine compliance with Special Condition No. 8.
   4. As an approved alternative to sorbent or stain tube testing, NH3 CEMS, or a second NOx CEMS, the permit holder may install and operate a dual stream system of NOx CEMS at the exit of the SCR. One of the exhaust streams would be routed, in an unconverted state, to one NOx CEMS, and the other exhaust stream would be routed through a NH3 converter to convert NH3 to NOx and then to a second NOx CEMS. The NH3 slip concentration shall be calculated from the difference between the two NOx CEMS readings (converted and unconverted). These results shall be recorded and used to determine compliance with Special Condition No. 8.
4. Any other method used for measuring NH3 slip shall require prior approval from the TCEQ Air Permits Division.
5. Audio, visual, and olfactory (AVO) checks for NH3 leaks within the FUG-7 area shall be made weekly. Following the detection of a leak, plant personnel shall take one or more of the following actions as soon as practicable: **(xx/20)**
   1. locate and isolate the leak, if necessary;
   2. commence repair or replacement of the leaking component; and
   3. use a leak collection/containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

Continuous Demonstration of Compliance for Unit 4

1. For each turbine stack in Unit 4, the holder of this permit shall install, calibrate, maintain, and operate a CEMS in accordance with 40 CFR Part 75 to demonstrate compliance with the maximum allowable emission rates for NOx, as indicated in Special Condition Nos. 1 and 11. Except for system breakdowns, repairs, calibration checks and zero and span adjustments required, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements. During any period of CEMS unavailability lasting longer than two hours (except for calibrations and routine maintenance), the holder of this permit shall maintain the water injection rate established by testing performed for the initial demonstration of compliance and shall demonstrate compliance by recording the water injection flow rate and unit load.

Continuous Demonstration of Compliance for Unit 6

1. For each turbine or heat recovery steam generator stack in Unit 6 (EPN SC-S6A and B; and CC-S6A and B) the holder of this permit shall install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NOX, CO and diluent gases [O2 or carbon dioxide (CO2)].
   1. The CEMS noted above shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B, or an acceptable alternative. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TCEQ Air Permits Division for requirements to be met. The CEMS shall meet the applicable quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1, or an acceptable alternative.
   2. The monitoring concentration data shall be reduced to hourly average values at least once every day, using a minimum of four equally-spaced data points from each one hour period. At least two valid data points shall be generated during the hourly period in which zero and span is performed.
   3. All monitoring data and quality-assurance data shall be maintained by the source for a period of five years and shall be made available to the TCEQ Executive Director or designated representative upon request.
   4. The TCEQ El Paso Regional Office shall be notified at least 21 days prior to any required relative accuracy test audit in order to provide that office the opportunity to observe the testing.
   5. If applicable, the CEMS for the turbines/duct burner stacks may be required to meet the design and performance specifications, pass the field tests, and meet the installation requirements and data analysis and reporting requirements specified in the applicable performance specifications in 40 CFR Part 75, Appendix A. The requirements of 40 CFR Part 75, Appendix A and B, respectively, are deemed an acceptable alternative to the performance specifications and quality assurance requirements of 40 CFR Part 60 for the NOx and O2 or CO2 CEMS.
2. The holder of this permit shall calculate hourly mass emissions in pounds per hour (lb/hr) using the EPA Reference Method 19 or a measured exhaust flow rate and the measured concentrations of NOx and CO from the CEMS required in Special Condition No. 22. Emissions shall be calculated and stored in an electronic format in pounds per hour, pounds per month and tons per year (based on any consecutive 12-month period). Records of this information shall also be available in a form suitable for inspection.
3. The NH3 concentration in each HRSG exhaust stack in Unit 6 (EPNs CC-S6A and B) shall be tested or calculated according to one of the methods listed below and shall be tested or calculated according to frequency listed below. Testing for NH3 slip is only required when the SCR unit is in operation.
   1. The holder of this permit may install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NH3. The NH3 concentrations shall be corrected and reported in accordance with Special Condition No. 8.
   2. As an approved alternative, the NH3 slip may be measured using a sorbent or stain tube device specific for NH3 measurement in the 2 to 30 ppm range. The frequency of sorbent or stain tube testing shall be at least one test per day for the first 60 days of operation, after which, the frequency may be reduced to at least one test per week. These results shall be recorded and used to determine compliance with Special Condition No. 8. Test results may consist of the average of three or more measurements.
   3. As an approved alternative to sorbent or stain tube testing or an NH3 CEMS, the permit holder may install and operate a second NOx CEMS probe located between the duct burners and the SCR, upstream of the stack NOx CEMS, which may be used in association with the SCR efficiency and NH3 injection rate to estimate NH3 slip. This condition shall not be construed to set a minimum NOx reduction efficiency on the SCR unit. These results shall be recorded and used to determine compliance with Special Condition No. 8.
   4. As an approved alternative to sorbent or stain tube testing, NH3 CEMS, or a second NOx CEMS, the permit holder may install and operate a dual stream system of NOx CEMS at the exit of the SCR. One of the exhaust streams would be routed, in an unconverted state, to one NOx CEMS, and the other exhaust stream would be routed through a NH3 converter to convert NH3 to NOx and then to a second NOx CEMS. The NH3 slip concentration shall be calculated from the difference between the two NOx CEMS readings (converted and unconverted). These results shall be recorded and used to determine compliance with Special Condition No. 8.
   5. Any other method used for measuring NH3 slip shall require prior approval from the TCEQ Air Permits Division.

Continuous Determination of Compliance for Cooling Towers

1. The Cooling Towers (EPN CT-1467-4 and CT-1467-6) shall not exceed a total dissolved solids (TDS) concentration of 9,000 parts per million by weight (ppmw) or mg/l as demonstrated based on measurements required by this Special Condition.
   1. A conservative default conversion factor of 0.80 (conductivity to TDS) may be used initially until a site specific demonstrated value is determined.
   2. The holder of this permit shall perform sampling to establish the conductivity to TDS conversion factor that shall be used by the permit holder to demonstrate compliance in accordance with Special Condition No. 25. A cooling water sample shall be collected monthly in each of the three calendar months following the start of the increase in TDS in the cooling water to 9,000 ppmw. In addition, a conductivity and TDS analysis shall be performed in accordance with "Standard Methods for the Examination of Water and Wastewater" Method 2510 (Conductivity) and Method 2540 (Solids) or EPA approved methods. An average conversion factor and standard deviation based on the three values shall be determined from the cooling water sample results.
   3. Within 45 days after completion of the sampling, copies of the sampling report shall be submitted to the TCEQ El Paso Regional Office.
   4. Continuous compliance with the lb/hr and TPY particulate matter emission rates for the Cooling Towers in the MAERT shall be demonstrated by the holder of this permit by monitoring the conductivity of the cooling water at a monitoring point in the recirculating water of each cooling tower, and recording these conductivity readings on a no less than monthly basis. Each conductivity measurement shall be converted to TDS concentration in ppmw or mg/l using the conductivity to TDS conversion factor established in accordance with Special Condition No. 25B.
   5. The monitoring data required by this special condition shall be kept for at least five years from the date monitoring is done, and the data shall be made available upon request to the EPA or TCEQ personnel.

Recordkeeping Requirements

1. The following information shall be made and maintained by the holder of this permit for a period of five years and shall be made available on request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction:
   1. The Unit 4, 6, and 7 CEMS data records required by Special Condition Nos. 14, 18, and 19 to demonstrate compliance with the NOx limitations, including any periods of CEMS downtime with reason for failure and corrective action.
   2. For Unit 4, water injection rates and turbine load records which are required by Special Condition Nos. 4A and 15.
   3. The starting time and duration of all periods of duct burner firing for Units 4 and 6.
   4. A log shall be kept to demonstrate compliance with the total Low Load annual operating hours for Unit 6, as noted in Special Condition No. 7.
   5. The SCR inlet temperature, during periods of SCR startup.
   6. Date and description of any routine, planned maintenance on the turbines or duct burners for Units 4, 6, and 7.
   7. Cooling Tower records shall include:
      1. The cooling tower ID with the monitoring point for the cooling tower recirculating water.
      2. The date and time of the monthly monitoring.
      3. The monthly measured conductivity and the equivalent TDS in parts per million or mg/l in the recirculating water of the cooling tower.
      4. Monthly records of the circulation rates for each cooling tower.
   8. Records of natural gas consumption and fuel sulfur content (as provided by the fuel suppliers) to demonstrate compliance with Special Condition No. 5.
   9. Records of diesel fuel use and the hours of operation of the engines to show compliance with Special Condition No. 10.
   10. Records of visible emission/opacity observations and corrective actions taken as specified in Special Condition No. 9.
   11. Records of AVO checks for ammonia leaks and maintenance performed to any piping and valves in NH3 service to show compliance with Special Condition Nos. 20 and 49. In addition, written records of any accidental releases, spills, or venting of NH3 and the corrective action taken. **(xx/20)**
   12. Records of planned maintenance, startup, and shutdown (MSS) activities as specified in Special Condition Nos. 32-37 and Attachment A, including the date, time, and duration of those activities, and emissions from those activities.
2. A copy of the current version of Pollution Control Project Standard Permit Registration No. 114528 shall be kept at the plant site and made immediately available at the request of personnel from the TCEQ, EPA, or any local air pollution control agency having jurisdiction.

Reporting

1. Reports of periods of excess emissions, periods of CEMS downtime (downtime for this report shall not include daily calibration checks and routine maintenance not exceeding two hours), and periods during CEMS downtime when the water injection system fails to maintain the required water injection rate for the turbine load, shall be submitted semi‑annually to the TCEQ El Paso Regional Office and the El Paso City-County Health District.

Offsets for Nonattainment New Source Review (NNSR) Permit (xx/20)

1. This Nonattainment New Source Review (NNSR) permit is issued/approved based on the requirement that the permit holder offset the project emission increase for facilities authorized by this permit prior to the commencement of operation, through participation in the TCEQ Emission Banking and Trading (EBT) Program in accordance with the rules in 30 TAC Chapter 101, Subchapter H.
2. Permit holder shall use 30.8 (This value should be in tenths of a ton because this is how ERCs are measured) tons per year (tpy) of (PM10) credits to offset the 30.8 tpy (PM10) project. The emission increase for the facilities authorized by this permit at a ratio of 1.0 to 1.0.
3. Prior to the commencement of operation, the permit holder shall obtain approval from the TCEQ EBT Program for the credits being used and then submit a permit alteration or amendment request to the TCEQ Air Permits Division (and copy the TCEQ Regional Office) to identify approved credits by TCEQ credit certificate number.

Maintenance, Startup, and Shutdown

1. This permit authorizes the emissions from the planned MSS activities listed in Attachment A and the MAERT, and these activities are limited to the emission limits specified on the MAERT. Attachment A identifies the inherently low emitting (ILE) planned maintenance activities that this permit authorizes to be performed.
2. The holder of this permit shall minimize emissions during planned MSS activities by operating the facility and associated air pollution control equipment in accordance with good air pollution control practices, safe operating practices, and protection of the facility.
3. Turbine combustion optimization maintenance activities associated with Unit 4 (EPNs S4-1 and S4-2), Unit 6 (EPNs SC-S6A and SC-S6B and EPNs CC-S6A and CC-S6B) and Unit 7 (EPN SC-7) are authorized, which includes leak and operability checks (e.g., turbine over-speed tests, troubleshooting), balancing, and tuning activities that occur during seasonal tuning, a combustor change-out, a major repair, maintenance to a combustor, or other similar circumstances. Combustion optimization maintenance activities shall not exceed eight hours per event. **(xx/20)**
4. Emissions during planned MSS activities will be minimized by limiting the duration of operation in planned startup and shutdown mode as follows:
   1. Unit 4 (EPNs S4-1 and S4-2)
      1. A planned startup of the electric generating facilities (EGFs) with EPNs S4-1 and S4-2 is defined as the period that begins when an initial flame detection signal is recorded in the plant’s Data Acquisition System (DAS) and ends when the water injection system has been online for at least 15 minutes and the turbine reaches an output of 15 megawatts (MW). A planned startup is limited to 480 minutes per event.
      2. A planned shutdown of the EGFs with EPNs S4-1 and S4-2 is defined as the period that begins when the water injection system goes offline and the turbine output drops below 55 MW and ends when a flame detection signal is no longer recorded in the DAS. A planned shutdown for each EGF is limited to 180 minutes per event.
   2. Unit 6 Simple Cycle (EPNs SC-S6A and SC-S6B)
      1. A planned startup of the electric generating facilities (EGFs) with EPNs SC-S6A and SC-S6B is defined as the period that begins when an initial flame detection signal is recorded in the plant’s DAS and ends when the DAS detects "pre-mix" signal for the combustion turbine. A planned startup is limited to 480 minutes per event.
      2. A planned shutdown of the EGFs with EPNs SC-S6A and SC-S6B is defined as the period that begins when the DAS no longer provides the "pre-mix" signal for the combustion turbine and output continues to drop until the DAS detects a "flame off" signal. A planned shutdown ends when a flame detection signal is no longer recorded in the DAS. A planned shutdown for each EGF is limited to 180 minutes per event.
   3. Unit 6 Combined Cycle (EPNs CC-S6A and CC-S6B)
      1. A planned startup of the electric generating facilities (EGFs) with EPNs CC-S6A and CC-S6B is defined as the period that begins when an initial flame detection signal is recorded in the plant’s DAS and ends when the ammonia injection system has been online for at least 15 minutes and the DAS detects "pre-mix" signal for the combustion turbine. A planned startup is limited to 480 minutes per event.
      2. A planned shutdown of the EGFs with EPNs CC-S6A and CC-S6B is defined as the period that begins when the DAS no longer provides the "pre-mix" signal for the combustion turbine, the ammonia injection system has gone offline, and output continues to drop until the DAS detects a "flame off" signal. A planned shutdown ends when a flame detection signal is no longer recorded in the DAS. A planned shutdown for each EGF is limited to 180 minutes per event.
   4. Unit 7 Simple Cycle (EPN SC-7) **(xx/20)**
      1. A planned startup of the EGF with EPN SC-7 is defined as the period that begins when an initial flame detection signal is recorded in the plant’s DAS and ends when the unit has reached base load.
      2. A planned shutdown of the EGF with EPN SC-7 is defined as the period that begins when the unit is no longer at base load and ends when the system detects flame out.
5. Compliance with the emissions limits for planned MSS activities identified in the MAERT attached to this permit shall be demonstrated as follows. The permit holder shall annually confirm the continued validity of the estimated potential to emit represented in the permit application for all ILE planned maintenance activities. The total emissions from all ILE planned maintenance activities (see Attachment A) shall be considered to be no more than the estimated potential to emit for those activities that are represented in the permit application.
6. With the exception of the emission limits in the MAERT attached to this permit, the permit conditions relating to planned MSS activities do not become effective until 180 days after issuance of the permit amendment that added such conditions.

Greenhouse Gases (GHG) (xx/20)

1. The turbine (EPN: SC-7) shall not exceed the following:

|  |  |
| --- | --- |
| **Turbine Model** | **Output Specific Carbon Dioxide (CO2) Emission Rate**  **(lb CO2/MWh)** |
| Mitsubishi M501 GAC | 1,200 |

Compliance with the above limit shall be demonstrated annually in accordance Special Condition No. 46

1. The 99 hp fire water pump engine (EPN FIRE-2) is limited to 100 hours of non-emergency operation, maintenance and testing, each engine, per year, on a rolling 12-month basis. The engine shall be equipped with a non-resettable elapsed run time meter.
2. The Turbine and the fuel gas heater (EPN LH-1) shall be limited to the use of pipeline quality natural gas.
3. The emergency fire water pump engine must use diesel fuel containing no more than 0.0015 percent (%) sulfur by weight.
4. Firing of any other fuel will require prior authorization from the Texas Commission on Environmental Quality (TCEQ) Air Permits Division.

Upon request by the Executive Director of the Texas Commission on Environmental Quality (TCEQ) or any local air pollution control program having jurisdiction, the permit holder shall provide a sample and/or an analysis of any fuel for these facilities or shall allow air pollution control agency representatives to obtain a sample for analysis.

Initial Demonstration of Compliance (GHG) (xx/20)

1. During the first thirty operating days after completion of certification testing of the continuous monitoring systems, or twelve calendar months, whichever comes first, the permit holder prepare calculations to demonstrate compliance with the applicable GHG limits in this permit. Within 45 days thereafter, the permit holder shall submit a report to the Region identifying whether the data causes any concerns regarding the permit holder's ability to comply with the GHG Special Conditions or the MAERT, and any actions that have been taken or are planned to be taken to address those concerns.

Continuous Demonstration of Compliance (Turbine) (xx/20)

1. The permit holder shall monitor and calculate natural gas fuel flow, electricity output, and GHG emissions, from the turbine (EPN SC-7) as specified in this permit.
2. Hourly Calculations
   1. Fuel Flow
      1. The holder of this permit shall install, calibrate, maintain, and operate a continuous fuel flow meter to measure and record the hourly natural gas consumption of the turbine (EPN SC-7).
      2. The fuel flow meter must meet the applicable requirements of 40 CFR Part 75, Appendix F and 40 CFR Part 60.
      3. The fuel flow meter must be accurate to ± 2.0 percent of the unit’s maximum flow.
      4. The fuel flow data must be automatically recorded and maintained on a data acquisition system.
   2. Heat input
      1. Calculate the heat input in MMBtu, consistent with Equation F-20 and the procedures for determining the HHV (High Heating Value), in 40 CFR Part 75, Appendix F, §5.5.2. In this section, the HHV is referred to as the gross calorific value of gaseous fuel (GCVg).
      2. The fuel supply shall be sampled and analyzed for HHV monthly.
   3. CO2 Emission Rate
      1. Calculate the hourly CO2 emission rate in short tons per hour, during all periods of operation, including MSS.
      2. Calculate the CO2 in accordance with 40 CFR Part 75, Appendix G, Section 2.3, Equation G-4, using:
         1. the default emission factor of 118.9 lb CO2/MMBtu; or
         2. a custom emission factor determined in accordance with 40 CFR Part 75, Appendix F, section 3.3.6, Equation 7-b.
   4. Methane (CH4) and nitrous oxide (N2O) emissions
      1. Calculate the CH4 and N2O emission rates in short tons per hour during all periods of operation, using the following:
         1. Measured hourly heat input; and
         2. Default emission factors Table C-2 of 40 CFR Part 98, Subpart C, version effective January 1, 2015.
   5. CO2e Emission Rate
      1. CO2e emission rate, in short tons per month, equals the sum of the CO2 emissions and the CO2e-converted emissions of CH4 and N2O.
      2. The CH4 and N2O emission rates are converted to CO2e emissions using the Global Warming Potentials of 25 for CH4 and 298 for N2O, from Table A-1 of 40 CFR Part 98, Subpart A, version effective January 1, 2015.
3. Annual Efficiency Demonstration and 12-month rolling data
   1. Following the initial compliance demonstration, the permit holder shall demonstrate compliance annually with the output-specific CO2 emissions limit in this permit. The emission rate is to be calculated using the following:
      * 1. Output-specific CO2 emissions are the sum of the hourly CO2 emissions for three consecutive hours divided by the sum of hourly MW production data for the same three-hour period.
        2. The annual 3-hour test for the output-specific CO2 emission rate shall be performed while the unit is operating as close to 100 percent load as possible under the ambient conditions, with or without evaporative cooling, corrected to 95oF and based on the gross electrical output (MW).
   2. Emissions of CO2, CH4, N2O, and CO2e in tons per year to show compliance with the limits of the MAERT.
      1. Monthly emissions are the sum of the hourly emissions for that month and include all periods of operation.
      2. At the end of each calendar month, add the monthly emissions to the monthly emissions for the previous 11 months.
4. In lieu of the CO2 calculation requirements of this permit, for a given turbine the permit holder may install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for CO2 emission measurements. The CEMS shall meet the specifications and test procedures for CO2 emission monitoring system at stationary sources, 40 CFR Part 98; or meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 3 and follow the monitoring requirements of 40 CFR § 60.13. The permit holder shall also measure volumetric flow and install a data acquisition and handling system to record all measurements.

Continuous Demonstration of Compliance (Circuit Breakers) (xx/20)

1. The sulfur hexafluoride (SF6)-enclosed circuit breakers used to prevent damage in the event of a power surge must be designed to meet the 2015 IEEE/IEC 62271-37-013 standard for high‑voltage circuit breakers. The circuit breakers must be guaranteed to achieve a SF6 leak rate of 0.5% by weight or less annually. The circuit breakers must be in a totally enclosed, pressurized compartment equipped with an alarm that signals the plant control room in the event that the density in any circuit breaker falls below the normal operating density as specified by the manufacturer.

The permit holder shall equip the circuit breakers with a low-density alarm and lockout. As soon as practicable following the detection of a leak, plant personnel shall take one or more of the following actions:

* 1. Locate and isolate the leak using a SF6 leak collections or containment system to control the leak until repair or replacement can be made if immediate repair is not possible.
  2. Commence repair or replacement of the leaking component.

Continuous Demonstration of Compliance (Natural Gas Fugitives) (xx/20)

1. The permit holder shall minimize emissions from pressurized components and equipment containing GHG as follows:
   1. Piping and valves in natural gas service within the operating area must be checked weekly for leaks using audio, visual, and olfactory (AVO) sensing for natural gas leaks. If the site is not manned for a given week, an AVO check shall be performed the within one week after plant personnel return to the site for the purpose of operating the facilities authorized by this permit.
   2. As soon as practicable following the detection of a leak, plant personnel shall take one or more of the following actions:
      1. Locate and isolate the leak, if necessary.
      2. Commence repair or replacement of the leaking component.

Additional Recordkeeping for GHG Emissions (xx/20)

1. Permit holders must keep records sufficient to demonstrate compliance with 30 Texas Administrative Code § 116.164. Records shall be sufficient to demonstrate the amount of emissions of GHGs from the source as a result of construction, a physical change or a change in method of operation does not require authorization under 30 TAC 116.164(a). Records shall be maintained for a period of five years after collection.
2. The following records shall be kept at the plant for the life of the permit. All records required in this permit shall be made available at the request of personnel from the TCEQ, EPA, or any air pollution control agency with jurisdiction:
   1. A copy of this permit.
   2. Permit application dated December 1, 2014, and subsequent representations submitted to the TCEQ.
3. The following information shall be maintained by the holder of this permit in a form suitable for inspection for a period of five years after collection and shall be made available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction:
   1. For the combustion turbine (EPN SC-7), records of the following:
      1. Fuel usage in MMBtu, kept hourly, monthly, and 12-month rolling basis.
      2. Averages of CH4, N2O, CO2, and CO2e emissions, kept hourly, monthly, and on a 12-month rolling average.
      3. Records of monthly sampling of natural gas HHV determinations.
      4. Records of the annual efficiency demonstration detailed in this permit.
   2. For the fire water pump engine (EPN FP-1), hours of operation on a monthly and rolling 12-month basis to show compliance with this permit.
   3. Records of triggered alarms and maintenance or leak repair performed on SF6 containing circuit breakers.
   4. Records of AVO checks on the natural gas fuel and maintenance performed to any piping and valves in natural gas service to show compliance with this permit.
   5. Records of calibrations, preventative maintenance, and/or repairs performed on fuel gas flow meters.

General Requirements

1. The following facilities are authorized by permits by rule (PBR) under Title 30 Texas Administrative Code Chapter 106 or by Standard Permit (SP). These authorizations are listed here for reference purposes only.

|  |  |
| --- | --- |
| Facilities | PBR/SP Authorization |
| Brazing, Soldering, Welding | § 106.227 |
| Routine Maintenance, Startup, and Shutdown of Facilities and Temporary Maintenance Facilities | § 106.263 |
| Handheld and Manually Operated Machines | § 106.265 |
| Surface Coating | § 106.433 |
| Abrasive Blasting, Outdoor | § 106.452 |
| Solvent Cleaning, Parts Degreaser | § 106.454 |
| Portable and Emergency Engines (operating fewer than 876 hours per year) | § 106.511 |
| Sludge Management | § 106.532 |
| Duct Burner Pollution Control Project | SP Registration No. 114528 |

Date: TBD

Attachment A

Permit Numbers 1467 and PSDTX1090

Inherently Low Emitting (ILE) Planned Maintenance Activities

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| ILE Planned Maintenance Activities | Emissions | | | | |
| NH3 | VOC | NOx | CO | PM |
| Air intake filter maintenance1 |  |  |  |  | x |
| Gaseous fuel venting2 |  | x |  |  |  |
| Sludge management |  | x |  |  |  |
| Ammonia system component change-out | x |  |  |  |  |
| Condensate removal from natural gas line knockout |  | x |  |  |  |
| Small equipment maintenance - high vapor pressure VOC3 |  | x |  |  |  |
| Condenser cleaning |  | x |  |  |  |
| Lube oil system |  | x |  |  |  |
| CEMS calibration |  |  | x | x |  |

Notes:

1. Includes, but is not limited to, combustion turbine air intake filters.
2. Includes, but is not limited to, venting prior to pipeline pigging, and meter proving.
3. Includes, but is not limited to, (i) repair/replacement of pumps, compressors, valves, pipes, flanges, transport lines, filters and screens in natural gas, fuel oil, diesel oil, ammonia, lube oil, and gasoline service, and (ii) vehicle and mobile equipment maintenance that may involve small VOC emissions, such as oil changes, transmission service, and hydraulic system service.

Date: March 20, 2015