Statement of Basis of the Federal Operating Permit

NRG Texas Power LLC

Site Name: W A Parish Electric Generating Station
Physical Location: 2500 Y U Jones Rd
Nearest City: Thompsons
County: Fort Bend

Permit Number: O74
Project Type: Renewal

The North American Industry Classification System (NAICS) Code: 221112
NAICS Name: Fossil Fuel Electric Power Generation

This Statement of Basis sets forth the legal and factual basis for the draft permit conditions in accordance with 30 TAC §122.201(a)(4). Per 30 TAC §§ 122.241 and 243, the permit holder has submitted an application under § 122.134 for permit renewal. This document may include the following information:

- A description of the facility/area process description;
- A basis for applying permit shields;
- A list of the federal regulatory applicability determinations;
- A table listing the determination of applicable requirements;
- A list of the New Source Review Requirements;
- The rationale for periodic monitoring methods selected;
- The rationale for compliance assurance methods selected;
- A compliance status; and
- A list of available unit attribute forms.

Prepared on: June 13, 2024

Operating Permit
Basis of Determination

Permit Area Process Description

NRG Texas Power LLC (NRG Texas) owns and operates the W A Parish Electric Generating Station (W A Parish), an electric power generating station located in Thompsons, Fort Bend County. The W A Parish plant consists of eight high-pressure boilers (Units 1 – 8) that produce steam for the generation of electricity. An auxiliary boiler provides steam for startup of Units 1, 2, and 4. The plant also has one natural gas-fired combustion turbine. Other equipment at the station includes natural gas piping components, coal and limestone handling equipment, cooling towers, degreasers, diesel-fired emergency engines, tanks, and oil-water separators.

The W. A. Parish Electric Generating Station consists of eight high pressure boilers (FINs: Units 1-8) which produce steam for the generation of electricity. These units operate on the Rankine cycle in which fuel is combusted to turn water into steam, which is used to turn a steam turbine connected to a generator, which produces electricity. Units 1-4 are natural gas-fired boilers, with Units 1-3 also authorized for waste oil firing. Units 5 and 6 are coal and natural gas-fired boilers, with the authorization to burn boiler cleaning wastewater. Units 7 and 8 are coal and natural gas-fired boilers, with the authorization to burn distillate fuel oil. Units 5-8 are equipped with low nitrogen oxide (NOx) burners and selective catalytic reduction (SCR) devices to control NOx emissions as well as activated carbon injection (ACI) systems to control mercury (Hg) emissions. Unit 8 is also equipped with a flue gas desulfurization (FGD) system to control sulfur dioxide emissions. An auxiliary boiler (FIN: AB1) provides steam for startup of Units 1, 2, and 4. The plant also has one natural gas-fired turbine (FIN: GT1) which is available to produce electricity in emergency situations.

Facilities at the station also include natural gas piping components, coal and limestone handling equipment, degreasers (EPNs: DEG-1 to DEG-7), engines (EPNs: ENG-168HP, ENG-250HP, ENG-435HP, ENG-44HP, ENG-504HP, ENG-650HP, and ENG-765HP), and oil-water separators (EPNs S1, S2, and S3). Degreasers are used in the shops for parts cleaning. The engines are used for emergency/backup equipment, such as fire water pumps, emergency generators, and mobile equipment. The oil-water separators are used for treating wastewater generated at the site.

The station also has 39 fixed-roof tanks used for the storage of gasoline, fuels, lubricating oils, water treatment chemicals, and various other chemicals used at the site.

FOPs at Site

The “application area” consists of the emission units and that portion of the site included in the application and this permit. Multiple FOPs may be issued to a site in accordance with 30 TAC § 122.201(e). When there is only one area for the site, then the application information and permit will include all units at the site. Additional FOPs that exist at the site, if any, are listed below.

Additional FOPs: O3611

Major Source Pollutants

The table below specifies the pollutants for which the site is a major source:

Major Pollutants	VOC, SO2, PM, NOX, HAPS, CO

Reading State of Texas’s Federal Operating Permit

The Title V Federal Operating Permit (FOP) lists all state and federal air emission regulations and New Source Review (NSR) authorizations (collectively known as “applicable requirements”) that apply at a particular site or permit area (in the event a site has multiple FOPs). **The FOP does not authorize new emissions or new construction activities.** The FOP begins with an introductory page which is common to all Title V permits. This page gives the details of the company, states the authority of the issuing agency, requires the company to operate in accordance with this permit and 30 Texas Administrative Code (TAC) Chapter 122, requires adherence with NSR requirements of 30 TAC Chapter 116, and finally indicates the permit number and the issuance date.

This is followed by the table of contents, which is generally composed of the following elements. Not all permits will have all of the elements.

- General Terms and Conditions
- Special Terms and Conditions
    - Emissions Limitations and Standards, Monitoring and Testing, and Recordkeeping and Reporting
    - Additional Monitoring Requirements
    - New Source Review Authorization Requirements
    - Compliance Requirements
    - Protection of Stratosphere Ozone
    - Permit Location
    - Permit Shield (30 TAC § 122.148)
- Attachments
    - Applicable Requirements Summary
        - Unit Summary
        - Applicable Requirements Summary
    - Additional Monitoring Requirements
    - Permit Shield
    - New Source Review Authorization References
    - Compliance Plan
    - Alternative Requirements
- Appendix A
    - Acronym list
- Appendix B
    - Copies of major NSR authorizations

General Terms and Conditions

The General Terms and Conditions are the same and appear in all permits. The first paragraph lists the specific citations for 30 TAC Chapter 122 requirements that apply to all Title V permit holders. The second paragraph describes the requirements for record retention. The third paragraph provides details for voiding the permit, if applicable. The fourth paragraph states that the permit holder shall comply with the requirements of 30 TAC Chapter 116 by obtaining a New Source Review authorization prior to new construction or modification of emission units located in the area covered by this permit. The fifth paragraph provides details on submission of reports required by the permit.

Special Terms and Conditions

Emissions Limitations and Standards, Monitoring and Testing, and Recordkeeping and Reporting. The TCEQ has designated certain applicable requirements as site-wide requirements. A site-wide requirement is a requirement that applies uniformly to all the units or activities at the site. Units with only site-wide requirements are addressed on Form OP-REQ1 and are not required to be listed separately on an OP-UA Form or Form OP-SUM. Form OP-SUM must list all units addressed in the application and provide identifying information, applicable OP-UA Forms, and preconstruction authorizations. The various OP-UA Forms provide the characteristics of each unit from which applicable requirements are established. Some exceptions exist as a few units may have both site-wide requirements and unit specific requirements.

Other conditions. The other entries under special terms and conditions are in general terms referring to compliance with the more detailed data listed in the attachments.

Attachments

Applicable Requirements Summary. The first attachment, the Applicable Requirements Summary, has two tables, addressing unit specific requirements. The first table, the Unit Summary, includes a list of units with applicable requirements, the unit type, the applicable regulation, and the requirement driver. The intent of the requirement driver is to inform the reader that a given unit may have several different operating scenarios and the differences between those operating scenarios.

The applicable requirements summary table provides the detailed citations of the rules that apply to the various units. For each unit and operating scenario, there is an added modifier called the “index number,” detailed citations specifying monitoring and testing requirements, recordkeeping requirements, and reporting requirements. The data for this table is based on data supplied by the applicant on the OP-SUM and various OP-UA forms.

Additional Monitoring Requirement. The next attachment includes additional monitoring the applicant must perform to ensure compliance with the applicable standard. Compliance assurance monitoring (CAM) is often required to provide a reasonable assurance of compliance with applicable emission limitations/standards for large emission units that use control devices to achieve compliance with applicant requirements. When necessary, periodic monitoring (PM) requirements are specified for certain parameters (i.e. feed rates, flow rates, temperature, fuel type and consumption, etc.) to determine if a term and condition or emission unit is operating within specified limits to control emissions. These additional monitoring approaches may be required for two reasons. First, the applicable rules do not adequately specify monitoring requirements (exception- Maximum Achievable Control Technology Standards (MACTs) generally have sufficient monitoring), and second, monitoring may be required to fill gaps in the monitoring requirements of certain applicable requirements. In situations where the NSR permit is the applicable requirement requiring extra monitoring for a specific emission unit, the preferred solution is to have the monitoring requirements in the NSR permit updated so that all NSR requirements are consolidated in the NSR permit.

Permit Shield. A permit may or may not have a permit shield, depending on whether an applicant has applied for, and justified the granting of, a permit shield. A permit shield is a special condition included in the permit document stating that compliance with the conditions of the permit shall be deemed compliance with the specified potentially applicable requirement(s) or specified applicable state-only requirement(s).

New Source Review Authorization References. All activities which are related to emissions in the state of Texas must have a NSR authorization prior to beginning construction. This section lists all units in the permit and the NSR authorization that allowed the unit to be constructed or modified. Units that do not have unit specific applicable requirements other than the NSR authorization do not need to be listed in this attachment. While NSR permits are not physically a part of the Title V permit, they are legally incorporated into the Title V permit by reference. Those NSR permits whose emissions exceed certain PSD/NA thresholds must also undergo a Federal review of federally regulated pollutants in addition to review for state regulated pollutants.

Compliance Plan. A permit may have a compliance schedule attachment for listing corrective actions plans for any emission unit that is out of compliance with an applicable requirement.

Alternative Requirements. This attachment will list any alternative monitoring plans or alternative means of compliance for applicable requirements that have been approved by the EPA Administrator and/or the TCEQ Executive Director.

Appendix A

Acronym list. This attachment lists the common acronyms used when discussing the FOPs.

Appendix B

Copies of major NSR authorizations applicable to the units covered by this permit have been included in this Appendix, to ensure that all interested persons can access those authorizations.

Stationary vents subject to 30 TAC Chapter 111, Subchapter A, § 111.111(a)(1)(B) addressed in the Special Terms and Conditions

The site contains stationary vents with a flowrate less than 100,000 actual cubic feet per minute (acfm) which are limited, over a six-minute average, to 20% opacity as required by 30 TAC § 111.111(a)(1)(B). As a site may have a large number of stationary vents that fall into this category, they are not required to be listed individually in the permit's Applicable Requirements Summary. This is consistent with EPA's White Paper for Streamlined Development of Part 70 Permit Applications, July 10, 1995, that states that requirements that apply identically to emission units at a site can be treated on a generic basis such as source-wide opacity limits.

Periodic monitoring is specified in Special Term and Condition 3 for stationary vents subject to 30 TAC § 111.111(a)(1)(B) to verify compliance with the 20% opacity limit. These vents are not expected to produce visible emissions during normal operation. The TCEQ evaluated the probability of these sources violating the opacity standards and determined that there is a very low potential that an opacity standard would be exceeded. It was determined that continuous monitoring for these sources is not warranted as there would be very limited environmental benefit in continuously monitoring sources that have a low potential to produce visible emissions. Therefore, the TCEQ set the visible observation monitoring frequency for these sources to once per calendar quarter.

The TCEQ has exempted vents that are not capable of producing visible emissions from periodic monitoring requirements. These vents include sources of colorless VOCs, non-fuming liquids, and other materials that cannot produce emissions that obstruct the transmission of light. Passive ventilation vents, such as plumbing vents, are also included in this category. Since this category of vents are not capable of producing opacity due to the physical or chemical characteristics of the emission source, periodic monitoring is not required as it would not yield any additional data to assure compliance with the 20% opacity standard of 30 TAC § 111.111(a)(1)(B).

In the event that visible emissions are detected, either through the quarterly observation or other credible evidence, such as observations from company personnel, the permit holder shall either report a deviation or perform a Test Method 9 observation to determine the opacity consistent with the 6-minute averaging time specified in 30 TAC § 111.111(a)(1)(B). An additional provision is included to monitor combustion sources more frequently than quarterly if alternate fuels are burned for periods greater than 24 consecutive hours. This will address possible emissions that may arise when switching fuel types.

The applicant opted to comply with the more stringent 20% opacity standard under 30 TAC § 111.111(a)(1)(B) for all stationary vents that are subject to the 30% opacity standard under 30 TAC § 111.111(a)(1)(A).

Stationary Vents subject to 30 TAC Chapter 111 not addressed in the Special Terms and Conditions

All other stationary vents subject to 30 TAC Chapter 111 not covered in the Special Terms and Conditions are listed in the permit's Applicable Requirements Summary. The basis for the applicability determinations for these vents are listed in the Determination of Applicable Requirements table.

Federal Regulatory Applicability Determinations

The following chart summarizes the applicability of the principal air pollution regulatory programs to the permit area:

Regulatory Program	Applicability (Yes/No)
Prevention of Significant Deterioration (PSD)	Yes
Nonattainment New Source Review (NNSR)	Yes
Minor NSR	Yes
40 CFR Part 60 - New Source Performance Standards	Yes
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants (NESHAPs)	No
40 CFR Part 63 - NESHAPs for Source Categories	Yes
Title IV (Acid Rain) of the Clean Air Act (CAA)	Yes
Title V (Federal Operating Permits) of the CAA	Yes
Title VI (Stratospheric Ozone Protection) of the CAA	Yes
CSAPR (Cross-State Air Pollution Rule)	Yes
Federal Implementation Plan for Regional Haze (Texas SO_2 Trading Program)	Yes

Basis for Applying Permit Shields

An operating permit applicant has the opportunity to specifically request a permit shield to document that specific applicable requirements do not apply to emission units in the permit. A permit shield is a special condition stating that compliance with the conditions of the permit shall be deemed compliance with the specified potentially applicable requirements or specified potentially applicable state-only requirements. A permit shield has been requested in the application for specific emission units. For the permit shield requests that have been approved, the basis of determination for regulations that the owner/operator need not comply with are located in the "Permit Shield" attachment of the permit.

Acid Rain Permit

The permitted area is subject to Federal Clean Air Act Title IV Acid Rain rules for Phase II units, as codified in 40 CFR Parts 72 through 78, because it meets the definition of "affected source." Applicability of affected sources are defined in 40 CFR § 72.6 and include those sources that burn fossil fuel and generates electricity for sale. Under 40 CFR Part 72, incorporated by reference into 30 TAC Chapter 122, all acid rain permits must contain specific terms and conditions, including monitoring, reporting, recordkeeping and excess emission requirements, established by the U.S. EPA. The Title IV permitting procedures are described within 30 TAC Chapter 122, Subchapter E. The applicable requirements of the Acid Rain Permit are contained in the Special Terms and Conditions of the FOP. The Acid Rain permit is effective as of the date of the issuance of the FOP and has a term ending in concurrence with the FOP.

Cross-State Air Pollution Rule

The Cross-State Air Pollution Rule (CSAPR) was established to mitigate the interstate transport of NO_x and SO_2 which contribute to the formation of fine particles ($PM_{2.5}$) and ground-level ozone and has replaced the previous Clean Air Interstate Rule (CAIR) program. The EPA has promulgated a model cap and trade program in 40 CFR Part 97 to implement CSAPR. While Texas is no longer included in the CSAPR NO_X or SO_2 Annual Trading Programs, Texas remains included in the CSAPR NO_X Ozone Season Group 2 Trading Program for the 2008 Ozone National Ambient Air Quality Standards. This rule has been adopted by reference into 30 TAC Chapter 122 as part of an effective rulemaking (Rule Project No. 2016-012-122-AI), which included the repeal of 30 TAC Chapter 122, Subchapter E, Division 2: Clean Air Interstate Rule.

The permitted area is subject to CSAPR as it contains units that meet a definition of a CSAPR unit in 40 CFR Part 97 (CSAPR NO_x and SO_2 Trading Programs). The applicable CSAPR requirements are contained in the Special Terms and Conditions of the FOP.

Federal Implementation Plan for Regional Haze (Texas SO_2 Trading Program)

EPA finalized a federal implementation plan creating a Texas-only trading program as an alternative to best available retrofit technology (BART) for SO_2 for electric generating units (EGUs) in the state of Texas and to address visibility transport in addition to partially addressing regional haze requirements for reasonable progress.

The permitted area is subject to the Texas SO_2 Trading Program as it contains units that meet the definition of a Texas SO_2 Trading Program unit in 40 CFR §52.2312 and Part 97, Subpart FFFFF (Texas SO_2 Trading Program). The applicable Texas SO_2 Trading Program requirements are contained in the Special Terms and Conditions of the FOP.

Insignificant Activities and Emission Units

In general, units not meeting the criteria for inclusion on either Form OP-SUM or Form OP-REQ1 are not required to be addressed in the operating permit application. Examples of these types of units include, but are not limited to, the following:

De Minimis Sources

1. Sources identified in the "De Minimis Facilities or Sources" list maintained by TCEQ. The list is available at https://www.tceq.texas.gov/permitting/air/newsourcereview/de_minimis.html.

Miscellaneous Sources

2. Office activities such as photocopying, blueprint copying, and photographic processes.

3. Outdoor barbecue pits, campfires, and fireplaces.
4. Storage and handling of sealed portable containers, cylinders, or sealed drums.
5. Vehicle exhaust from maintenance or repair shops.
6. Storage and use of non-VOC products or equipment for maintaining motor vehicles operated at the site (including but not limited to, antifreeze and fuel additives).
7. Air contaminant detectors and recorders, combustion controllers and shut-off devices, product analyzers, laboratory analyzers, continuous emissions monitors, other analyzers and monitors, and emissions associated with sampling activities. Exception to this category includes sampling activities that are deemed fugitive emissions and under a regulatory leak detection and repair program.
8. Steam vents, steam leaks, and steam safety relief valves, provided the steam (or boiler feedwater) has not contacted other materials or fluids containing regulated air pollutants other than boiler water treatment chemicals.
9. Storage of water that has not contacted other materials or fluids containing regulated air pollutants other than boiler water treatment chemicals.
10. Well cellars.
11. Fire or emergency response equipment and training, including but not limited to, use of fire control equipment including equipment testing and training, and open burning of materials or fuels associated with firefighting training.
12. Equipment used exclusively for the melting or application of wax.
13. Instrument systems utilizing air, natural gas, nitrogen, oxygen, carbon dioxide, helium, neon, argon, krypton, and xenon.
14. Battery recharging areas.

Sources Authorized by 30 TAC Chapter 106, Permits by Rule

15. Sources authorized by §106.102: Combustion units designed and used exclusively for comfort heating purposes employing liquid petroleum gas, natural gas, solid wood, or distillate fuel oil.
16. Sources authorized by §106.122: Bench scale laboratory equipment and laboratory equipment used exclusively for chemical and physical analysis, including but not limited to, assorted vacuum producing devices and laboratory fume hoods.
17. Sources authorized by §106.141: Batch mixers with rated capacity of 27 cubic feet or less for mixing cement, sand, aggregate, lime, gypsum, additives, and/or water to produce concrete, grout, stucco, mortar, or other similar products.
18. Sources authorized by §106.143: Wet sand and gravel production facilities that obtain material from subterranean and subaqueous beds where the deposits of sand and gravel are consolidated granular materials resulting from natural disintegration of rock and stone and have a production rate of 500 tons per hour or less.
19. Sources authorized by §106.148: Railcar or truck unloading of wet sand, gravel, aggregate, coal, lignite, and scrap iron or scrap steel (but not including metal ores, metal oxides, battery parts, or fine dry materials) into trucks or other railcars for transportation to other locations.
20. Sources authorized by §106.149: Sand and gravel production facilities that obtain material from deposits of sand and gravel consisting of natural disintegration of rock and stone, provided that crushing or breaking operations are not used and no blasting is conducted to obtain the material.
21. Sources authorized by §106.161: Animal feeding operations which confine animals in numbers specified and any associated on-site feed handling and/or feed millings operations, not including caged laying and caged pullet operations.
22. Sources authorized by §106.162: Livestock auction sales facilities.
23. Sources authorized by §106.163: All animal racing facilities, domestic animal shelters, zoos, and their associated confinement areas, stables, feeding areas, and waste collection and treatment facilities, other than incineration units.
24. Sources authorized by §106.229: Equipment used exclusively for the dyeing or stripping of textiles.
25. Sources authorized by §106.241: Any facility where animals or poultry are slaughtered and prepared for human consumption provided that waste products such as blood, offal, and feathers are stored in such a manner as to prevent the creation of a nuisance condition and these waste products are removed from the premises daily or stored under refrigeration.
26. Sources authorized by §106.242: Equipment used in eating establishments for the purpose of preparing food for human consumption.
27. Sources authorized by §106.243: Smokehouses in which the maximum horizontal inside cross-sectional area does not exceed 100 square feet.
28. Sources authorized by §106.244: Ovens, mixers, blenders, barbecue pits, and cookers if the products are edible and intended for human consumption.

29. Sources authorized by §106.266: Vacuum cleaning systems used exclusively for industrial, commercial, or residential housekeeping purposes.
30. Sources authorized by §106.301: Aqueous fertilizer storage tanks.
31. Sources authorized by §106.313: All closed tumblers used for the cleaning or deburring of metal products without abrasive blasting, and all open tumblers with a batch capacity of 1,000 lbs. or less.
32. Sources authorized by §106.316: Equipment used for inspection of metal products.
33. Sources authorized by §106.317: Equipment used exclusively for rolling, forging, pressing, drawing, spinning, or extruding either hot or cold metals by some mechanical means.
34. Sources authorized by §106.318: Die casting machines.
35. Sources authorized by §106.319: Foundry sand mold forming equipment to which no heat is applied.
36. Sources authorized by §106.331: Equipment used exclusively to package pharmaceuticals and cosmetics or to coat pharmaceutical tablets.
37. Sources authorized by §106.333: Equipment used exclusively for the mixing and blending of materials at ambient temperature to make water-based adhesives.
38. Sources authorized by §106.372: Any air separation or other industrial gas production, storage, or packaging facility. Industrial gases, for purposes of this list, include only oxygen, nitrogen, helium, neon, argon, krypton, and xenon.
39. Sources authorized by §106.391: Presses used for the curing of rubber products and plastic products.
40. Sources authorized by §106.394: Equipment used for compression molding and injection molding of plastics.
41. Sources authorized by §106.414: Equipment used exclusively for the packaging of lubricants or greases.
42. Sources authorized by §106.415: Laundry dryers, extractors, and tumblers used for fabrics cleaned with water solutions of bleach or detergents.
43. Sources authorized by §106.431: Equipment used exclusively to mill or grind coatings and molding compounds where all materials charged are in paste form.
44. Sources authorized by §106.432: Containers, reservoirs, or tanks used exclusively for dipping operations for coating objects with oils, waxes, or greases where no organic solvents, diluents, or thinners are used; or dipping operations for applying coatings of natural or synthetic resins which contain no organic solvents.
45. Sources authorized by §106.451: Blast cleaning equipment using a suspension of abrasives in water.
46. Sources authorized by §106.453: Equipment used for washing or drying products fabricated from metal or glass, provided no volatile organic materials are used in the process and no oil or solid fuel is burned.
47. Sources authorized by §106.471: Equipment used exclusively to store or hold dry natural gas.
48. Sources authorized by §106.531: Sewage treatment facilities, excluding combustion or incineration equipment, land farms, or grease trap waste handling or treatment facilities.

Determination of Applicable Requirements

The tables below include the applicability determinations for the emission units, the index number(s) where applicable, and all relevant unit attribute information used to form the basis of the applicability determination. The unit attribute information is a description of the physical properties of an emission unit which is used to determine the requirements to which the permit holder must comply. For more information about the descriptions of the unit attributes specific Unit Attribute Forms may be viewed at www.tceq.texas.gov/permitting/air/nav/air_all_ua_forms.html.

A list of unit attribute forms is included at the end of this document. Some examples of unit attributes include construction date; product stored in a tank; boiler fuel type; etc.. Generally, multiple attributes are needed to determine the requirements for a given emission unit and index number. The table below lists these attributes in the column entitled "Basis of Determination." Attributes that demonstrate that an applicable requirement applies will be the factual basis for the specific citations in an applicable requirement that apply to a unit for that index number. The TCEQ Air Permits Division has developed flowcharts for determining applicability of state and federal regulations based on the unit attribute information in a Decision Support System (DSS). These flowcharts can be accessed via the internet at www.tceq.texas.gov/permitting/air/nav/air_supportsys.html. The Air Permits Division staff may also be contacted for assistance at (512) 239-1250.

The attributes for each unit and corresponding index number provide the basis for determining the specific legal citations in an applicable requirement that apply, including emission limitations or standards, monitoring, recordkeeping, and reporting. The rules were found to apply or not apply by using the unit attributes as answers to decision questions found in the flowcharts of the DSS. Some additional attributes indicate which legal citations of a rule apply. The legal citations that apply to each emission unit may be found in the Applicable Requirements Summary table of the draft permit. There may be some entries or rows of units and rules not found in the permit, or if the permit contains a permit shield, repeated in the permit shield area. These are sets of attributes that describe negative applicability, or; in other words, the reason why a potentially applicable requirement does not apply.

If applicability determinations have been made which differ from the available flowcharts, an explanation of the decisions involved in the applicability determination is specified in the column “Changes and Exceptions to RRT.” If there were no exceptions to the DSS, then this column has been removed.

The draft permit includes all emission limitations or standards, monitoring, recordkeeping and reporting required by each applicable requirement. If an applicable requirement does not require monitoring, recordkeeping, or reporting, the word “None” will appear in the Applicable Requirements Summary table. If additional periodic monitoring is required for an applicable requirement, it will be explained in detail in the portion of this document entitled “Rationale for Compliance Assurance Monitoring (CAM)/ Periodic Monitoring Methods Selected.”

When attributes demonstrate that a unit is not subject to an applicable requirement, the applicant may request a permit shield for those items. The portion of this document entitled “Basis for Applying Permit Shields” specifies which units, if any, have a permit shield.

Operational Flexibility

When an emission unit has multiple operating scenarios, it will have a different index number associated with each operating condition. This means that units are permitted to operate under multiple operating conditions. The applicable requirements for each operating condition are determined by a unique set of unit attributes. For example, a tank may store two different products at different points in time. The tank may, therefore, need to comply with two distinct sets of requirements, depending on the product that is stored. Both sets of requirements are included in the permit, so that the permit holder may store either product in the tank.

Determination of Applicable Requirements

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
ENG-168HP	40 CFR Part 60, Subpart IIII	60IIII	Applicability Date = Stationary CI ICE commenced construction, reconstruction, or modification on or before 07/11/2005.	
ENG-168HP	40 CFR Part 63, Subpart ZZZZ	63ZZZZ-01	HAP Source = The site is a major source of hazardous air pollutants as defined in 40 CFR § 63.2 Brake HP = Stationary RICE with a brake HP greater than or equal to 100 HP and less than 250 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002. Service Type = Emergency use where the RICE does not operate as specified in 40 CFR §63.6640(f)(2)(ii) and (iii) or does not operate as specified in 40 CFR §63.6640(f)(4)(ii). Stationary RICE Type = Compression ignition engine	
ENG-250HP	40 CFR Part 60, Subpart IIII	60IIII	Applicability Date = Stationary CI ICE commenced construction, reconstruction, or modification on or before 07/11/2005.	
ENG-250HP	40 CFR Part 63, Subpart ZZZZ	63ZZZZ-01	HAP Source = The site is a major source of hazardous air pollutants as defined in 40 CFR § 63.2 Brake HP = Stationary RICE with a brake HP greater than or equal to 250 HP and less than 300 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002. Service Type = Emergency use where the RICE does not operate as specified in 40 CFR §63.6640(f)(2)(ii) and (iii) or does not operate as specified in 40 CFR §63.6640(f)(4)(ii). Stationary RICE Type = Compression ignition engine	
ENG-435HP	40 CFR Part 60, Subpart IIII	60IIII	Applicability Date = Stationary CI ICE commenced construction, reconstruction, or modification on or before 07/11/2005.	
ENG-435HP	40 CFR Part 63, Subpart ZZZZ	63ZZZZ-01	HAP Source = The site is a major source of hazardous air pollutants as defined in 40 CFR § 63.2 Brake HP = Stationary RICE with a brake HP greater than or equal to 300 HP and less than or equal to 500 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002. Service Type = Emergency use where the RICE does not operate as specified in 40 CFR §63.6640(f)(2)(ii) and (iii) or does not operate as specified in 40 CFR §63.6640(f)(4)(ii). Stationary RICE Type = Compression ignition engine	
ENG-44HP	40 CFR Part 60, Subpart IIII	60IIII	Applicability Date = Stationary CI ICE commenced construction, reconstruction, or modification on or before 07/11/2005.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
ENG-44HP	40 CFR Part 63, Subpart ZZZZ	63ZZZZ-01	HAP Source = The site is a major source of hazardous air pollutants as defined in 40 CFR § 63.2 Brake HP = Stationary RICE with a brake HP less than 100 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002. Service Type = Emergency use where the RICE does not operate as specified in 40 CFR §63.6640(f)(2)(ii) and (iii) or does not operate as specified in 40 CFR §63.6640(f)(4)(ii). Stationary RICE Type = Compression ignition engine	
ENG-504HP	40 CFR Part 60, Subpart IIII	60IIII	Applicability Date = Stationary CI ICE commenced construction, reconstruction, or modification on or before 07/11/2005.	
ENG-504HP	40 CFR Part 63, Subpart ZZZZ	63ZZZZ-01	HAP Source = The site is a major source of hazardous air pollutants as defined in 40 CFR § 63.2 Brake HP = Stationary RICE with a brake HP greater than 500 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002. Service Type = Emergency use where the RICE does not operate as specified in 40 CFR §63.6640(f)(2)(ii) and (iii) or does not operate as specified in 40 CFR §63.6640(f)(4)(ii). Stationary RICE Type = Compression ignition engine	
ENG-650HP	40 CFR Part 60, Subpart IIII	60IIII	Applicability Date = Stationary CI ICE commenced construction, reconstruction, or modification on or before 07/11/2005.	
ENG-650HP	40 CFR Part 63, Subpart ZZZZ	63ZZZZ-01	HAP Source = The site is a major source of hazardous air pollutants as defined in 40 CFR § 63.2 Brake HP = Stationary RICE with a brake HP greater than 500 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002. Service Type = Emergency use where the RICE does not operate as specified in 40 CFR §63.6640(f)(2)(ii) and (iii) or does not operate as specified in 40 CFR §63.6640(f)(4)(ii). Stationary RICE Type = Compression ignition engine	
ENG-765HP	40 CFR Part 60, Subpart IIII	60IIII	Applicability Date = Stationary CI ICE commenced construction, reconstruction, or modification on or before 07/11/2005.	
ENG-765HP	40 CFR Part 63, Subpart ZZZZ	63ZZZZ-01	HAP Source = The site is a major source of hazardous air pollutants as defined in 40 CFR § 63.2 Brake HP = Stationary RICE with a brake HP greater than 500 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002. Service Type = Emergency use where the RICE does not operate as specified in 40 CFR §63.6640(f)(2)(ii) and (iii) or does not operate as specified in 40 CFR §63.6640(f)(4)(ii).	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Stationary RICE Type = Compression ignition engine	
B-110-1	40 CFR Part 60, Subpart Ka	60Ka	Product Stored = Petroleum liquid (other than petroleum or condensate) Storage Capacity = Capacity is 40,000 gallons (151,416 liters) or less	
B-110-1T	30 TAC Chapter 115, Storage of VOCs	R5112-1	Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is less than or equal to 1,000 gallons	
B-110-1T	40 CFR Part 60, Subpart Kb	60Kb	Product Stored = Petroleum liquid (other than petroleum or condensate) Storage Capacity = Capacity is less than 10,600 gallons (40,000 liters)	
B-110-2	40 CFR Part 60, Subpart Ka	60Ka	Product Stored = Petroleum liquid (other than petroleum or condensate) Storage Capacity = Capacity is 40,000 gallons (151,416 liters) or less	
B-110-2T	30 TAC Chapter 115, Storage of VOCs	R5112-1	Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is less than or equal to 1,000 gallons	
B-110-2T	40 CFR Part 60, Subpart Kb	60Kb	Product Stored = Petroleum liquid (other than petroleum or condensate) Storage Capacity = Capacity is less than 10,600 gallons (40,000 liters)	
B-111	30 TAC Chapter 115, Storage of VOCs	R5112-1	Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is less than or equal to 1,000 gallons	
B-111	40 CFR Part 60, Subpart Kb	60Kb	Product Stored = Petroleum liquid (other than petroleum or condensate) Storage Capacity = Capacity is less than 10,600 gallons (40,000 liters)	
B-116-2	30 TAC Chapter 115, Storage of VOCs	R5112-1	Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Product Stored = Gasoline from a storage container in motor vehicle fuel dispensing service (as defined in 30 TAC Chapter 115) Storage Capacity = Capacity is less than 25,000 gallons	
B-116-2	40 CFR Part 60, Subpart K	60K	Construction/Modification Date = After March 8, 1974 and on or before May 19, 1978 Storage Capacity = Capacity is 40,000 gallons (151,416 liters) or less	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
B-117	30 TAC Chapter 115, Storage of VOCs	R5112-1	Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is less than or equal to 1,000 gallons	
B-117	40 CFR Part 60, Subpart Ka	60Ka	Product Stored = Petroleum liquid (other than petroleum or condensate) Storage Capacity = Capacity is 40,000 gallons (151,416 liters) or less	
B-158	30 TAC Chapter 115, Storage of VOCs	R5112-1	Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is less than or equal to 1,000 gallons	
B-158	40 CFR Part 60, Subpart K	60K	Construction/Modification Date = After March 8, 1974 and on or before May 19, 1978 Storage Capacity = Capacity is 40,000 gallons (151,416 liters) or less	
B-162	30 TAC Chapter 115, Storage of VOCs	R5112-1	Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is less than or equal to 1,000 gallons	
GRPTK1	30 TAC Chapter 115, Storage of VOCs	R5112-1	Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is greater than 1,000 gallons but less than or equal to 25,000 gallons Tank Description = Tank does not require emission controls True Vapor Pressure = True vapor pressure is less than 1.0 psia	
GRPTK1	40 CFR Part 60, Subpart K	60K	Construction/Modification Date = After March 8, 1974 and on or before May 19, 1978 Storage Capacity = Capacity is 40,000 gallons (151,416 liters) or less	
GRPTK2	30 TAC Chapter 115, Storage of VOCs	R5112-1	Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is greater than 1,000 gallons but less than or equal to 25,000 gallons Tank Description = Tank does not require emission controls True Vapor Pressure = True vapor pressure is less than 1.0 psia	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
GRPTK2	40 CFR Part 60, Subpart K	60K	Construction/Modification Date = After March 8, 1974 and on or before May 19, 1978 Storage Capacity = Capacity is 40,000 gallons (151,416 liters) or less	
GRPTK3	30 TAC Chapter 115, Storage of VOCs	R5112-1	Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is greater than 1,000 gallons but less than or equal to 25,000 gallons Tank Description = Tank does not require emission controls True Vapor Pressure = True vapor pressure is less than 1.0 psia	
GRPTK3	40 CFR Part 60, Subpart Ka	60Ka	Product Stored = Petroleum liquid (other than petroleum or condensate) Storage Capacity = Capacity is 40,000 gallons (151,416 liters) or less	
GRPTK4	30 TAC Chapter 115, Storage of VOCs	R5112-1	Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is greater than 1,000 gallons but less than or equal to 25,000 gallons Tank Description = Tank does not require emission controls True Vapor Pressure = True vapor pressure is less than 1.0 psia	
GRPTK4	40 CFR Part 60, Subpart Kb	60Kb	Product Stored = Petroleum liquid (other than petroleum or condensate) Storage Capacity = Capacity is less than 10,600 gallons (40,000 liters)	
WAPGAS	30 TAC Chapter 115, Loading and Unloading of VOC	R5212-1	Chapter 115 Facility Type = Motor vehicle fuel dispensing facility	
WAPUNLOAD	30 TAC Chapter 115, Loading and Unloading of VOC	R5212-1	Chapter 115 Facility Type = Facility type other than a gasoline terminal, gasoline bulk plant, motor vehicle fuel dispensing facility or marine terminal. Alternate Control Requirement (ACR) = No alternate control requirements are being utilized. Product Transferred = Volatile organic compounds other than liquefied petroleum gas and gasoline. Transfer Type = Only unloading. True Vapor Pressure = True vapor pressure less than 0.5 psia.	
3	30 TAC Chapter 112, Sulfur Compounds	REG2-1	Fuel Type = Liquid fuel. Heat Input = Design heat input is greater than 250 MMBtu/hr. Control Equipment = Unit not equipped with SO_2 control equipment.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Stack Height = The effective stack height is at least the standard effective stack height for each stack to which the unit routes emissions.	
3	30 TAC Chapter 117, Utility Electric Generation	R71200-1	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Natural gas. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is not used to control NO_x emissions.	
3	30 TAC Chapter 117, Utility Electric Generation	R71200-2	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Fuel oil. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is not used to control NO_x emissions.	
3	30 TAC Chapter 117, Utility Electric Generation	R71200-3	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Natural gas. Fuel Type #2 = Fuel oil. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1).	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is not used to control NO_x emissions.	
3	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = On or before August 17, 1971.	
3	40 CFR Part 60, Subpart Da	60Da-1	Construction/Modification Date = ON/BEFORE SEPTEMBER 18, 1978	
3	40 CFR Part 60, Subpart Db	60Db-1	Construction/Modification Date = On or before June 19, 1984.	
3	40 CFR Part 60, Subpart Dc	60Dc-1	Construction/Modification Date = On or before June 9, 1989.	
3	40 CFR Part 60, Subpart TTTT	60TTTT-1	Unit Type = Steam generating unit Construction/Modification Date = Constructed on or before January 8, 2014	
4	30 TAC Chapter 117, Utility Electric Generation	R71200-1	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Natural gas. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is not used to control NO_x emissions.	
4	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = On or before August 17, 1971.	
4	40 CFR Part 60, Subpart Da	60Da-1	Construction/Modification Date = ON/BEFORE SEPTEMBER 18, 1978	
4	40 CFR Part 60, Subpart Db	60Db-1	Construction/Modification Date = On or before June 19, 1984.	
4	40 CFR Part 60, Subpart Dc	60Dc-1	Construction/Modification Date = On or before June 9, 1989.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
4	40 CFR Part 60, Subpart TTTT	60TTTT-1	Unit Type = Steam generating unit Construction/Modification Date = Constructed on or before January 8, 2014	
7	30 TAC Chapter 111, Nonagricultural Processes	R1151-3	Source Type = Solid fossil fuel-fired steam generator.	
7	30 TAC Chapter 112, Sulfur Compounds	REG2-1	Fuel Type = Solid fossil fuel. Heat Input = Design heat input is greater than 1500 MMBtu/hr. Control Equipment = Unit not equipped with SO_2 control equipment.	
7	30 TAC Chapter 112, Sulfur Compounds	REG2-2	Fuel Type = Liquid fuel. Heat Input = Design heat input is greater than 250 MMBtu/hr. Control Equipment = Unit not equipped with SO_2 control equipment. Stack Height = The effective stack height is at least the standard effective stack height for each stack to which the unit routes emissions.	
7	30 TAC Chapter 117, Utility Electric Generation	R71200-1	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Coal. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	
7	30 TAC Chapter 117, Utility Electric Generation	R71200-2	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Natural gas. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired.	-- Affected Pollutant - NH3: Reporting Requirements: §117.8010, [G]§117.8010(1), §117.8010(2), §117.8010(2)(A), §117.8010(2)(B), [G]§117.8010(3), §117.8010(4), [G]§117.8010(5), §117.8010(6), [G]§117.8010(7), and [G]§117.8010(8) citations were added with project 22115, as the stack test reports are applicable for all pollutants and have been carried forward.

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	
7	30 TAC Chapter 117, Utility Electric Generation	R71200-3	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Coal. Fuel Type #2 = Natural gas. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	
7	30 TAC Chapter 117, Utility Electric Generation	R71200-4	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Fuel oil. Fuel Type #2 = Natural gas. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
7	30 TAC Chapter 117, Utility Electric Generation	R71200-5	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than 2.2(10^{11}) Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Coal. Fuel Type #2 = Fuel oil. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	
7	30 TAC Chapter 117, Utility Electric Generation	R71200-6	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than 2.2(10^{11}) Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Coal. Fuel Type #2 = Fuel oil. Fuel Type #3 = Natural gas. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	
7	30 TAC Chapter 117, Utility Electric Generation	R71200-7	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than 2.2(10^{11}) Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Coal. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF).	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Unit is complying with an Alternative Case Specific Specifications under 30 TAC §§ 117.1025, 117.1225 or 117.1325. CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Unit is complying with an Alternative Case Specific Specification under 30 TAC §§ 117.1025, 117.1225 or 117.1325. NH3 Emission Monitoring System = Not using CEMS or PEMS.	
7	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = After December 22, 1976, and on or before September 18, 1978. Covered Under Subpart Da or KKKK = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da or 40 CFR Part 60, Subpart KKKK. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. PM CEMS = The facility does not use a CEMS to measure PM. Opacity Monitoring = Continuous opacity monitoring system for measuring the opacity of emissions. Gas/Liquid Fuel = The facility does not burn only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 0.060 lb/MMBtu or less and does not use post combustion technology to reduce emissions of SO_2 or PM. Fuels with 0.30 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. Specific Site = The facility is not Southwestern Public Service Company's Harrington Station #1 in Amarillo, TX. D-Series Fuel Type #1 = Gaseous fossil fuel other than natural gas. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. SO2 Monitoring = No monitoring is required for SO_2 emissions because there is no applicable SO_2 emission limit. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
7	40 CFR Part 60, Subpart D	60D-2	Construction/Modification Date = After December 22, 1976, and on or before September 18, 1978. Covered Under Subpart Da or KKKK = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da or 40 CFR Part 60, Subpart KKKK. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. PM CEMS = The facility does not use a CEMS to measure PM. Opacity Monitoring = Continuous opacity monitoring system for measuring the opacity of emissions. Gas/Liquid Fuel = The facility does not burn only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 0.060 lb/MMBtu or less and does not use post combustion technology to reduce emissions of SO_2 or PM. Fuels with 0.30 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. Specific Site = The facility is not Southwestern Public Service Company's Harrington Station #1 in Amarillo, TX. D-Series Fuel Type #1 = Solid fossil fuel (fuel that is not lignite, at least 25% coal refuse, or at least 25% lignite mined in North Dakota, South Dakota, or Montana. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. SO2 Monitoring = No monitoring is required for SO_2 emissions because there is no applicable SO_2 emission limit. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44.	
7	40 CFR Part 60, Subpart D	60D-3	Construction/Modification Date = After December 22, 1976, and on or before September 18, 1978. Covered Under Subpart Da or KKKK = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da or 40 CFR Part 60, Subpart KKKK. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. PM CEMS = The facility does not use a CEMS to measure PM.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Opacity Monitoring = Continuous opacity monitoring system for measuring the opacity of emissions. Gas/Liquid Fuel = The facility does not burn only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 0.060 lb/MMBtu or less and does not use post combustion technology to reduce emissions of SO_2 or PM. Fuels with 0.30 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. Specific Site = The facility is not Southwestern Public Service Company's Harrington Station #1 in Amarillo, TX. D-Series Fuel Type #1 = Gaseous fossil fuel other than natural gas. D-Series Fuel Type #2 = Solid fossil fuel (fuel that is not lignite, at least 25% coal refuse, or at least 25% lignite mined in North Dakota, South Dakota, or Montana. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. SO2 Monitoring = No monitoring is required for SO_2 emissions because there is no applicable SO_2 emission limit. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44.	
7	40 CFR Part 60, Subpart D	60D-4	Construction/Modification Date = After December 22, 1976, and on or before September 18, 1978. Covered Under Subpart Da or KKKK = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da or 40 CFR Part 60, Subpart KKKK. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. PM CEMS = The facility does not use a CEMS to measure PM. Opacity Monitoring = Continuous opacity monitoring system for measuring the opacity of emissions. Gas/Liquid Fuel = The facility does not burn only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 0.060 lb/MMBtu or less and does not use post combustion technology to reduce emissions of SO_2 or PM. Fuels with 0.30 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Specific Site = The facility is not Southwestern Public Service Company's Harrington Station #1 in Amarillo, TX. D-Series Fuel Type #1 = Liquid fossil fuel. D-Series Fuel Type #2 = Gaseous fossil fuel other than natural gas. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. SO2 Monitoring = No monitoring is required for SO_2 emissions because there is no applicable SO_2 emission limit. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44.	
7	40 CFR Part 60, Subpart D	60D-5	Construction/Modification Date = After December 22, 1976, and on or before September 18, 1978. Covered Under Subpart Da or KKKK = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da or 40 CFR Part 60, Subpart KKKK. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. PM CEMS = The facility does not use a CEMS to measure PM. Opacity Monitoring = Continuous opacity monitoring system for measuring the opacity of emissions. Gas/Liquid Fuel = The facility does not burn only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 0.060 lb/MMBtu or less and does not use post combustion technology to reduce emissions of SO_2 or PM. Fuels with 0.30 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. Specific Site = The facility is not Southwestern Public Service Company's Harrington Station #1 in Amarillo, TX. D-Series Fuel Type #1 = Liquid fossil fuel. D-Series Fuel Type #2 = Solid fossil fuel (fuel that is not lignite, at least 25% coal refuse, or at least 25% lignite mined in North Dakota, South Dakota, or Montana. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			SO2 Monitoring = No monitoring is required for SO_2 emissions because there is no applicable SO_2 emission limit. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44.	
7	40 CFR Part 60, Subpart D	60D-6	Construction/Modification Date = After December 22, 1976, and on or before September 18, 1978. Covered Under Subpart Da or KKKK = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da or 40 CFR Part 60, Subpart KKKK. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. PM CEMS = The facility does not use a CEMS to measure PM. Opacity Monitoring = Continuous opacity monitoring system for measuring the opacity of emissions. Gas/Liquid Fuel = The facility does not burn only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 0.060 lb/MMBtu or less and does not use post combustion technology to reduce emissions of SO_2 or PM. Fuels with 0.30 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. Specific Site = The facility is not Southwestern Public Service Company's Harrington Station #1 in Amarillo, TX. D-Series Fuel Type #1 = Liquid fossil fuel. D-Series Fuel Type #2 = Gaseous fossil fuel other than natural gas. D-Series Fuel Type #3 = Solid fossil fuel (fuel that is not lignite, at least 25% coal refuse, or at least 25% lignite mined in North Dakota, South Dakota, or Montana. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. SO2 Monitoring = No monitoring is required for SO_2 emissions because there is no applicable SO_2 emission limit. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44.	
7	40 CFR Part 60, Subpart Da	60Da-1	Construction/Modification Date = ON/BEFORE SEPTEMBER 18, 1978	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
7	40 CFR Part 60, Subpart Db	60Db-1	Construction/Modification Date = On or before June 19, 1984.	
7	40 CFR Part 60, Subpart Dc	60Dc-1	Construction/Modification Date = On or before June 9, 1989.	
7	40 CFR Part 60, Subpart TTTT	60TTTT-1	Unit Type = Steam generating unit Construction/Modification Date = Constructed on or before January 8, 2014	
7	40 CFR Part 63, Subpart UUUUU	63UUUUU	§63.9983(a) = The unit is not designated a stationary combustion turbine, other than an IGCC unit, covered by 40 CFR part 63, subpart YYYY, per §63.9983(a). §63.9983(b) = The unit is coal- or oil-fired and combusts natural gas in accordance with §63.9983(b). §63.9983(c) = The unit can not combust more than 25 MW of coal or oil or is not complying with §63.9983(c). §63.9983(d) = The unit does not combust hazardous waste per §63.9983(d). Limited-use Liquid = The unit does not qualify as a limited-use liquid oil-fired unit as defined in §63.10042. Construction Status = The EGU is not new or reconstructed. Start-Up = The start-up date of the affected source was before April 16, 2012. Unit Fuel = The EGU is designed for coal with a heating value greater than or equal to 8,300 Btu/lb. Pollutant-a = Filterable PM is a surrogate for total HAP or total non-Hg HAP metals. PM-Input = A heat input-based limit is used for PM. Pollutant-b = Hydrogen chloride is a surrogate for acid gas HAP. HCl-Input = A heat input-based limit is used for hydrogen chloride. Hg-Input-c = A heat input-based limit is used for mercury. Hg LEE Test = LEE Testing is conducted for 30 days. Scrubber/Bypass = The EGU is not equipped with an acid gas scrubber or does not have a main stack and bypass stack exhaust configuration. PM-LEE = The unit is qualifying as a low emitting EGU (LEE) for filterable PM. HCl-LEE = The unit is qualifying as a low emitting EGU (LEE) for hydrogen chloride. Hg-LEE-c = The unit is not qualifying as a low emitting EGU (LEE) for mercury. Startup = Not relying on paragraph (2) definition of “startup” in §63.10042. Compliance Demo = A CEMS (or sorbent trap) is used to demonstrate compliance. Stack Config = Single unit-single stack configuration. O2-CO2 CEMS = An oxygen or carbon dioxide CEMS is used to convert measured pollutant concentrations. Flow Monitor = A stack gas flow rate monitor is used for routine operation of a sorbent trap monitoring system or to convert measured pollutant concentrations.	<u>Monitoring/Testing:</u> § 63.10009, § 63.10020(d), § 63.10022(a)(1), § 63.10022(a)(4), and § 63.10022(b) have been added emissions averaging citations specified in 40 CFR Part 63, Subpart UUUUU. <u>Reporting Requirements:</u> [G]§ 63.10032(e) has been added emissions averaging citations specified in 40 CFR Part 63, Subpart UUUUU.

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Gas Moisture = Not required to make corrections for stack gas moisture when converting pollutants. Direct HAP = A CEMS or sorbent trap is used to measure HAP directly.	
8	30 TAC Chapter 111, Nonagricultural Processes	R1151-3	Source Type = Solid fossil fuel-fired steam generator.	
8	30 TAC Chapter 112, Sulfur Compounds	REG2-1	Fuel Type = Solid fossil fuel. Heat Input = Design heat input is greater than 1500 MMBtu/hr. Control Equipment = Unit equipped with SO_2 control equipment. FCAA § 412(c) = The unit is subject to the Federal Clean Air Act § 412(c) [FCAA § 412(c)] as amended in 1990.	
8	30 TAC Chapter 112, Sulfur Compounds	REG2-2	Fuel Type = Liquid fuel. Heat Input = Design heat input is greater than 250 MMBtu/hr. Control Equipment = Unit equipped with SO_2 control equipment. FCAA § 412(c) = The unit is subject to the Federal Clean Air Act § 412(c) [FCAA § 412(c)] as amended in 1990. Stack Height = The effective stack height is at least the standard effective stack height for each stack to which the unit routes emissions.	
8	30 TAC Chapter 117, Utility Electric Generation	R71200-1	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than 2.2(10^{11}) Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Coal. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	
8	30 TAC Chapter 117, Utility Electric Generation	R71200-2	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than 2.2(10^{11}) Btu/yr. Service Type = Utility boiler (other than peaking service).	-- Affected Pollutant - NH3: Reporting Requirements: §117.8010, [G]§117.8010(1), §117.8010(2), §117.8010(2)(A), §117.8010(2)(B), [G]§117.8010(3), §117.8010(4),

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Fuel Type #1 = Natural gas. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	[G]§117.8010(5), §117.8010(6), [G]§117.8010(7), and [G]§117.8010(8) citations were added with project 22115, as the stack test reports are applicable for all pollutants and have been carried forward.
8	30 TAC Chapter 117, Utility Electric Generation	R71200-3	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Fuel oil. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	
8	30 TAC Chapter 117, Utility Electric Generation	R71200-4	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Fuel oil. Fuel Type #2 = Natural gas. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	
8	30 TAC Chapter 117, Utility Electric Generation	R71200-5	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Coal. Fuel Type #2 = Fuel oil. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	
8	30 TAC Chapter 117, Utility Electric Generation	R71200-6	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Coal. Fuel Type #2 = Fuel oil. Fuel Type #3 = Natural gas. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	
8	30 TAC Chapter 117, Utility Electric Generation	R71200-7	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service).	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Fuel Type #1 = Coal. Fuel Type #2 = Natural gas. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	
8	30 TAC Chapter 117, Utility Electric Generation	R71200-8	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Coal. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Unit is complying with an Alternative Case Specific Specifications under 30 TAC §§ 117.1025, 117.1225 or 117.1325. CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Unit is complying with an Alternative Case Specific Specification under 30 TAC §§ 117.1025, 117.1225 or 117.1325. NH3 Emission Monitoring System = Not using CEMS or PEMS.	
8	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = After September 18, 1978. Covered Under Subpart Da or KKKK = The steam generating unit is covered under 40 CFR Part 60, Subpart Da or 40 CFR Part 60, Subpart KKKK.	
8	40 CFR Part 60, Subpart Da	60Da-1	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). D-Series Fuel Type #1 = Solid fossil fuel. Changes to Existing Affected Facility = A change has not been made to the existing steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Combined Cycle Type = Not a combined cycle gas turbine or a unit subject to NSPS Eb or CCCC PM Commercial Demonstration Permit = The facility does not meet the PM exemptions in § 60.42Da(f)(1) or (2) Unit Type = Not a resource recovery unit. PM Monitoring Type = Monitoring other than a CEMS, predictive monitor or COMS for electrostatic precipitator or leak detection for a baghouse. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system [§ 60.49Da(b)(1) or (b)(2)]. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. SO2 Commercial Demonstration Permit = The facility is not operating under an SO2 commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da SO2 Emission Rate = SO_2 emission rate is greater than or equal to 0.20 lb/MMBtu (86 ng/J) heat input but less than or equal to 0.60 lb/MMBtu (260 ng/J) heat input. FGD = The facility has a flue gas desulfurization system. NOx Commercial Demonstration Permit = The facility is not operating under a NOx commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da Duct Burner = The unit is not a duct burner.	
8	40 CFR Part 60, Subpart Da	60Da-2	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). D-Series Fuel Type #1 = Natural gas. Changes to Existing Affected Facility = A change has not been made to the existing steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired Combined Cycle Type = Not a combined cycle gas turbine or a unit subject to NSPS Eb or CCCC PM Commercial Demonstration Permit = The facility does not meet the PM exemptions in § 60.42Da(f)(1) or (2) Unit Type = Not a resource recovery unit. PM Monitoring Type = Monitoring other than a CEMS, predictive monitor or COMS for electrostatic precipitator or leak detection for a baghouse. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system [§ 60.49Da(b)(1) or (b)(2)]. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. SO2 Commercial Demonstration Permit = The facility is not operating under an SO2 commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da SO2 Emission Rate = SO_2 emission rate is greater than or equal to 0.20 lb/MMBtu (86 ng/J) heat input but less than or equal to 0.60 lb/MMBtu (260 ng/J) heat input.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			FGD = The facility has a flue gas desulfurization system. NOx Commercial Demonstration Permit = The facility is not operating under a NOx commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da Duct Burner = The unit is not a duct burner.	
8	40 CFR Part 60, Subpart Da	60Da-3	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). D-Series Fuel Type #1 = Liquid fossil fuel. Changes to Existing Affected Facility = A change has not been made to the existing steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired Combined Cycle Type = Not a combined cycle gas turbine or a unit subject to NSPS Eb or CCCC PM Commercial Demonstration Permit = The facility does not meet the PM exemptions in § 60.42Da(f)(1) or (2) Unit Type = Not a resource recovery unit. PM Monitoring Type = Monitoring other than a CEMS, predictive monitor or COMS for electrostatic precipitator or leak detection for a baghouse. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system [§ 60.49Da(b)(1) or (b)(2)]. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. SO2 Commercial Demonstration Permit = The facility is not operating under an SO2 commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da SO2 Emission Rate = SO_2 emission rate is greater than or equal to 0.20 lb/MMBtu (86 ng/J) heat input but less than or equal to 0.60 lb/MMBtu (260 ng/J) heat input. FGD = The facility has a flue gas desulfurization system. NOx Commercial Demonstration Permit = The facility is not operating under a NOx commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da Duct Burner = The unit is not a duct burner.	
8	40 CFR Part 60, Subpart Da	60Da-4	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). D-Series Fuel Type #1 = Liquid fossil fuel. D-Series Fuel Type #2 = Solid fossil fuel. Changes to Existing Affected Facility = A change has not been made to the existing steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired Combined Cycle Type = Not a combined cycle gas turbine or a unit subject to NSPS Eb or CCCC	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			PM Commercial Demonstration Permit = The facility does not meet the PM exemptions in § 60.42Da(f)(1) or (2) Unit Type = Not a resource recovery unit. PM Monitoring Type = Monitoring other than a CEMS, predictive monitor or COMS for electrostatic precipitator or leak detection for a baghouse. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system [§ 60.49Da(b)(1) or (b)(2)]. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. SO2 Commercial Demonstration Permit = The facility is not operating under an SO2 commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da SO2 Emission Rate = SO_2 emission rate is greater than or equal to 0.20 lb/MMBtu (86 ng/J) heat input but less than or equal to 0.60 lb/MMBtu (260 ng/J) heat input. FGD = The facility has a flue gas desulfurization system. NOx Commercial Demonstration Permit = The facility is not operating under a NOx commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da	
8	40 CFR Part 60, Subpart Da	60Da-5	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). D-Series Fuel Type #1 = Liquid fossil fuel. D-Series Fuel Type #2 = Natural gas. Changes to Existing Affected Facility = A change has not been made to the existing steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired Combined Cycle Type = Not a combined cycle gas turbine or a unit subject to NSPS Eb or CCCC PM Commercial Demonstration Permit = The facility does not meet the PM exemptions in § 60.42Da(f)(1) or (2) Unit Type = Not a resource recovery unit. PM Monitoring Type = Monitoring other than a CEMS, predictive monitor or COMS for electrostatic precipitator or leak detection for a baghouse. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system [§ 60.49Da(b)(1) or (b)(2)]. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. SO2 Commercial Demonstration Permit = The facility is not operating under an SO2 commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da SO2 Emission Rate = SO_2 emission rate is greater than or equal to 0.20 lb/MMBtu (86 ng/J) heat input but less than or equal to 0.60 lb/MMBtu (260 ng/J) heat input. FGD = The facility has a flue gas desulfurization system.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			NOx Commercial Demonstration Permit = The facility is not operating under a NOx commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da	
8	40 CFR Part 60, Subpart Da	60Da-6	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). D-Series Fuel Type #1 = Liquid fossil fuel. D-Series Fuel Type #2 = Solid fossil fuel. D-Series Fuel Type #3 = Natural gas. Changes to Existing Affected Facility = A change has not been made to the existing steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired Combined Cycle Type = Not a combined cycle gas turbine or a unit subject to NSPS Eb or CCCC PM Commercial Demonstration Permit = The facility does not meet the PM exemptions in § 60.42Da(f)(1) or (2) Unit Type = Not a resource recovery unit. PM Monitoring Type = Monitoring other than a CEMS, predictive monitor or COMS for electrostatic precipitator or leak detection for a baghouse. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system [§ 60.49Da(b)(1) or (b)(2)]. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. SO2 Commercial Demonstration Permit = The facility is not operating under an SO2 commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da SO2 Emission Rate = SO_2 emission rate is greater than or equal to 0.20 lb/MMBtu (86 ng/J) heat input but less than or equal to 0.60 lb/MMBtu (260 ng/J) heat input. FGD = The facility has a flue gas desulfurization system. NOx Commercial Demonstration Permit = The facility is not operating under a NOx commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da	
8	40 CFR Part 60, Subpart Da	60Da-7	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). D-Series Fuel Type #1 = Solid fossil fuel. D-Series Fuel Type #2 = Natural gas. Changes to Existing Affected Facility = A change has not been made to the existing steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired Combined Cycle Type = Not a combined cycle gas turbine or a unit subject to NSPS Eb or CCCC	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			PM Commercial Demonstration Permit = The facility does not meet the PM exemptions in § 60.42Da(f)(1) or (2) Unit Type = Not a resource recovery unit. PM Monitoring Type = Monitoring other than a CEMS, predictive monitor or COMS for electrostatic precipitator or leak detection for a baghouse. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system [§ 60.49Da(b)(1) or (b)(2)]. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. SO2 Commercial Demonstration Permit = The facility is not operating under an SO2 commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da SO2 Emission Rate = SO_2 emission rate is greater than or equal to 0.20 lb/MMBtu (86 ng/J) heat input but less than or equal to 0.60 lb/MMBtu (260 ng/J) heat input. FGD = The facility has a flue gas desulfurization system. NOx Commercial Demonstration Permit = The facility is not operating under a NOx commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da	
8	40 CFR Part 60, Subpart Db	60Db-1	Construction/Modification Date = On or before June 19, 1984.	
8	40 CFR Part 60, Subpart Dc	60Dc-1	Construction/Modification Date = On or before June 9, 1989.	
8	40 CFR Part 60, Subpart TTTT	60TTTT-1	Unit Type = Steam generating unit Construction/Modification Date = Constructed on or before January 8, 2014	
8	40 CFR Part 63, Subpart UUUUU	63UUUUU1	§63.9983(a) = The unit is not designated a stationary combustion turbine, other than an IGCC unit, covered by 40 CFR part 63, subpart YYYY, per §63.9983(a). §63.9983(b) = The unit is coal- or oil-fired and combusts natural gas in accordance with §63.9983(b). §63.9983(c) = The unit can not combust more than 25 MW of coal or oil or is not complying with §63.9983(c). §63.9983(d) = The unit does not combust hazardous waste per §63.9983(d). Limited-use Liquid = The unit does not qualify as a limited-use liquid oil-fired unit as defined in §63.10042. Construction Status = The EGU is not new or reconstructed. Start-Up = The start-up date of the affected source was before April 16, 2012. Unit Fuel = The EGU is designed for coal with a heating value greater than or equal to 8,300 Btu/lb. Pollutant-a = Filterable PM is a surrogate for total HAP or total non-Hg HAP metals. PM-Input = A heat input-based limit is used for PM. Pollutant-b = Hydrogen chloride is a surrogate for acid gas HAP.	Monitoring/Testing: § 63.10009, § 63.10020(d), § 63.10022(a)(1), § 63.10022(a)(4), and § 63.10022(b) have been added emissions averaging citations specified in 40 CFR Part 63, Subpart UUUUU. Reporting Requirements: [G]§ 63.10032(e) has been added emissions averaging citations specified in 40 CFR Part 63, Subpart UUUUU.

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			HCl-Input = A heat input-based limit is used for hydrogen chloride. Hg-Input-c = A heat input-based limit is used for mercury. Hg LEE Test = LEE Testing is conducted for 30 days. Scrubber/Bypass = The EGU is not equipped with an acid gas scrubber or does not have a main stack and bypass stack exhaust configuration. PM-LEE = The unit is qualifying as a low emitting EGU (LEE) for filterable PM. HCl-LEE = The unit is qualifying as a low emitting EGU (LEE) for hydrogen chloride. Hg-LEE-c = The unit is not qualifying as a low emitting EGU (LEE) for mercury. Startup = Not relying on paragraph (2) definition of "startup" in §63.10042. Compliance Demo = A CEMS (or sorbent trap) is used to demonstrate compliance. Stack Config = Unit with multiple parallel control devices with multiple stacks. O2-CO2 CEMS = An oxygen or carbon dioxide CEMS is used to convert measured pollutant concentrations. Flow Monitor = A stack gas flow rate monitor is used for routine operation of a sorbent trap monitoring system or to convert measured pollutant concentrations. Gas Moisture = Not required to make corrections for stack gas moisture when converting pollutants. Direct HAP = A CEMS or sorbent trap is used to measure HAP directly.	
AB1	30 TAC Chapter 117, Utility Electric Generation	R71200-1	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Auxiliary boiler that is an affected facility under 40 CFR Part 60, Subpart D, Db, or Dc. Fuel Type #1 = Natural gas. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Not using CEMS or PEMS. Ammonia Use = Ammonia injection is not used to control NO_x emissions.	
AB1	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = After September 18, 1978. Covered Under Subpart Da or KKKK = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da or 40 CFR Part 60, Subpart KKKK. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Heat Input Rate = Heat input rate is less than or equal to 250 MMBtu/hr (73 MW).	
AB1	40 CFR Part 60, Subpart Da	60Da-1	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Heat Input of Fossil Fuel = Heat input of fossil fuel is less than or equal to 250 MMBtu/hr (73 MW).	
AB1	40 CFR Part 60, Subpart Db	60Db-1	Construction/Modification Date = On or after November 25, 1986, and on or before July 9, 1997. Heat Input Capacity = Heat input capacity is greater than 100 MMBtu/hr (29 MW) but less than or equal to 250 MMBtu/hr (73 MW). Subpart Da = The affected facility does not meet applicability requirements of 40 CFR Part 60, Subpart Da. Changes to Existing Affected Facility = No change has been made to the existing steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Db, for the sole purpose of combusting gases containing totally reduced sulfur as defined under 40 CFR § 60.281. Subpart Ea, Eb or AAAA = The affected facility does not meet applicability requirements of and is subject to 40 CFR Part 60, Subpart Ea, Eb or AAAA. Subpart KKKK = The affected facility is not a heat recovery steam generator associated with combined cycle gas turbines and that meets applicability requirements of and is subject to 40 CFR Part 60, Subpart KKKK. Subpart Cb or BBBB = The affected facility is not covered by an EPA approved State or Federal section 111(d)/129 plan implementing 40 CFR Part 60, Subpart Cb or BBBB emission guidelines. D-Series Fuel Type #1 = Natural gas. Subpart J = The affected facility does not meet applicability requirements of 40 CFR Part 60, Subpart J. Subpart E = The affected facility does not meet applicability requirements of 40 CFR Part 60, Subpart E. ACF Option - SO2 = Other ACF or no ACF. ACF Option - PM = Other ACF or no ACF. ACF Option - NOx = Other ACF or no ACF. 60.49Da(n) Alternative = The facility is not using the § 60.49Da(n) alternative. 60.49Da(m) Alternative = The facility is not using the § 60.49Da(m) alternative. PM Monitoring Type = No particulate monitoring. Opacity Monitoring Type = No particulate (opacity) monitoring. NOx Monitoring Type = Continuous emission monitoring system. SO2 Monitoring Type = No SO_2 monitoring. Technology Type = No emerging or conventional technology is used to reduce or control SO2 emissions Unit Type = OTHER UNIT TYPE Heat Release Rate = Natural gas oil with a heat release rate greater than 70 MBtu/hr/ft^3.	
AB1	40 CFR Part 60, Subpart Dc	60Dc-1	Construction/Modification Date = On or before June 9, 1989.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
AB1	40 CFR Part 63, Subpart DDDDD	63DDDDD	Commence = Source is existing (commenced construction or reconstruction on or before June 4, 2010) Table Applicability = The unit is designed to burn Gas 1 fuel AND has no continuous oxygen trim AND has heat input equal to or greater than 10 MMBtu/hr	
GRP-B1-2	30 TAC Chapter 112, Sulfur Compounds	REG2-1	Fuel Type = Liquid fuel. Heat Input = Design heat input is greater than 250 MMBtu/hr. Control Equipment = Unit not equipped with SO_2 control equipment. Stack Height = The effective stack height is at least the standard effective stack height for each stack to which the unit routes emissions.	
GRP-B1-2	30 TAC Chapter 117, Utility Electric Generation	R71200-1	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Natural gas. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is not used to control NO_x emissions.	
GRP-B1-2	30 TAC Chapter 117, Utility Electric Generation	R71200-2	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Fuel oil. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is not used to control NO_x emissions.	
GRP-B1-2	30 TAC Chapter 117, Utility Electric Generation	R71200-3	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service).	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Fuel Type #1 = Natural gas. Fuel Type #2 = Fuel oil. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Tangential-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is not used to control NO_x emissions.	
GRP-B1-2	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = On or before August 17, 1971.	
GRP-B1-2	40 CFR Part 60, Subpart Da	60Da-1	Construction/Modification Date = ON/BEFORE SEPTEMBER 18, 1978	
GRP-B1-2	40 CFR Part 60, Subpart Db	60Db-1	Construction/Modification Date = On or before June 19, 1984.	
GRP-B1-2	40 CFR Part 60, Subpart Dc	60Dc-1	Construction/Modification Date = On or before June 9, 1989.	
GRP-B1-2	40 CFR Part 60, Subpart TTTT	60TTTT-1	Unit Type = Steam generating unit Construction/Modification Date = Constructed on or before January 8, 2014	
GRP-B5-6	30 TAC Chapter 111, Nonagricultural Processes	R1151-3	Source Type = Solid fossil fuel-fired steam generator.	
GRP-B5-6	30 TAC Chapter 112, Sulfur Compounds	REG2-1	Fuel Type = Solid fossil fuel. Heat Input = Design heat input is greater than 1500 MMBtu/hr. Control Equipment = Unit not equipped with SO_2 control equipment.	
GRP-B5-6	30 TAC Chapter 117, Utility Electric Generation	R71200-1	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Natural gas. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Wall-fired.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	
GRP-B5-6	30 TAC Chapter 117, Utility Electric Generation	R71200-2	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Coal. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Wall-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	-- Affected Pollutant - NH3: Reporting Requirements: §117.8010, [G]§117.8010(1), §117.8010(2), §117.8010(2)(A), §117.8010(2)(B), [G]§117.8010(3), §117.8010(4), [G]§117.8010(5), §117.8010(6), [G]§117.8010(7), and [G]§117.8010(8) citations were added with project 22115, as the stack test reports are applicable for all pollutants and have been carried forward.
GRP-B5-6	30 TAC Chapter 117, Utility Electric Generation	R71200-3	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Natural gas. Fuel Type #2 = Coal. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Wall-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). NH3 Emission Monitoring System = Not using CEMS or PEMS.	
GRP-B5-6	30 TAC Chapter 117, Utility	R71200-4	Date Placed in Service = On or before November 15, 1992.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
	Electric Generation		Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. Service Type = Utility boiler (other than peaking service). Fuel Type #1 = Coal. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). Fuel Firing Option = Wall-fired. NOx Monitoring System = Continuous emission monitoring system. CO Emission Limitation = Unit is complying with an Alternative Case Specific Specifications under 30 TAC §§ 117.1025, 117.1225 or 117.1325. CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Unit is complying with an Alternative Case Specific Specification under 30 TAC §§ 117.1025, 117.1225 or 117.1325. NH3 Emission Monitoring System = Not using CEMS or PEMS.	
GRP-B5-6	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = After August 17, 1971, and on or before December 22, 1976. Covered Under Subpart Da or KKKK = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da or 40 CFR Part 60, Subpart KKKK. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. PM CEMS = The facility does not use a CEMS to measure PM. Opacity Monitoring = Continuous opacity monitoring system for measuring the opacity of emissions. Gas/Liquid Fuel = The facility does not burn only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 0.060 lb/MMBtu or less and does not use post combustion technology to reduce emissions of SO_2 or PM. Fuels with 0.30 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. Specific Site = The facility is not Southwestern Public Service Company's Harrington Station #1 in Amarillo, TX. D-Series Fuel Type #1 = Gaseous fossil fuel other than natural gas. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. SO2 Monitoring = No monitoring is required for SO_2 emissions because there is no applicable SO_2 emission limit.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Cyclone-Fired Unit = The unit is not a cyclone-fired unit. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44.	
GRP-B5-6	40 CFR Part 60, Subpart D	60D-2	Construction/Modification Date = After August 17, 1971, and on or before December 22, 1976. Covered Under Subpart Da or KKKK = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da or 40 CFR Part 60, Subpart KKKK. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. PM CEMS = The facility does not use a CEMS to measure PM. Opacity Monitoring = Continuous opacity monitoring system for measuring the opacity of emissions. Gas/Liquid Fuel = The facility does not burn only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 0.060 lb/MMBtu or less and does not use post combustion technology to reduce emissions of SO_2 or PM. Fuels with 0.30 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. Specific Site = The facility is not Southwestern Public Service Company's Harrington Station #1 in Amarillo, TX. D-Series Fuel Type #1 = Solid fossil fuel (fuel that is not lignite, at least 25% coal refuse, or at least 25% lignite mined in North Dakota, South Dakota, or Montana. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. SO2 Monitoring = No monitoring is required for SO_2 emissions because there is no applicable SO_2 emission limit. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44.	
GRP-B5-6	40 CFR Part 60, Subpart D	60D-3	Construction/Modification Date = After August 17, 1971, and on or before December 22, 1976. Covered Under Subpart Da or KKKK = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da or 40 CFR Part 60, Subpart KKKK. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			PM CEMS = The facility does not use a CEMS to measure PM. Opacity Monitoring = Continuous opacity monitoring system for measuring the opacity of emissions. Gas/Liquid Fuel = The facility does not burn only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 0.060 lb/MMBtu or less and does not use post combustion technology to reduce emissions of SO_2 or PM. Fuels with 0.30 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. Specific Site = The facility is not Southwestern Public Service Company's Harrington Station #1 in Amarillo, TX. D-Series Fuel Type #1 = Gaseous fossil fuel other than natural gas. D-Series Fuel Type #2 = Solid fossil fuel (fuel that is not lignite, at least 25% coal refuse, or at least 25% lignite mined in North Dakota, South Dakota, or Montana. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. SO2 Monitoring = No monitoring is required for SO_2 emissions because there is no applicable SO_2 emission limit. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. NOx Monitoring Type = It was demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44.	
GRP-B5-6	40 CFR Part 60, Subpart Da	60Da-1	Construction/Modification Date = ON/BEFORE SEPTEMBER 18, 1978	
GRP-B5-6	40 CFR Part 60, Subpart Db	60Db-1	Construction/Modification Date = On or before June 19, 1984.	
GRP-B5-6	40 CFR Part 60, Subpart Dc	60Dc-1	Construction/Modification Date = On or before June 9, 1989.	
GRP-B5-6	40 CFR Part 60, Subpart TTTT	60TTTT-1	Unit Type = Steam generating unit Construction/Modification Date = Constructed on or before January 8, 2014	
GRP-B5-6	40 CFR Part 63, Subpart UUUUU	63UUUUU	§63.9983(a) = The unit is not designated a stationary combustion turbine, other than an IGCC unit, covered by 40 CFR part 63, subpart YYYY, per §63.9983(a). §63.9983(b) = The unit is coal- or oil-fired and combusts natural gas in accordance with §63.9983(b). §63.9983(c) = The unit can not combust more than 25 MW of coal or oil or is not complying with §63.9983(c). §63.9983(d) = The unit does not combust hazardous waste per §63.9983(d).	Monitoring/Testing: § 63.10009, § 63.10020(d), § 63.10022(a)(1), § 63.10022(a)(4), and § 63.10022(b) have been added emissions averaging citations specified in 40 CFR Part 63, Subpart UUUUU. Reporting Requirements: [G]§ 63.10032(e) has been added emissions

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Limited-use Liquid = The unit does not qualify as a limited-use liquid oil-fired unit as defined in §63.10042. Construction Status = The EGU is not new or reconstructed. Start-Up = The start-up date of the affected source was before April 16, 2012. Unit Fuel = The EGU is designed for coal with a heating value greater than or equal to 8,300 Btu/lb. Pollutant-a = Filterable PM is a surrogate for total HAP or total non-Hg HAP metals. PM-Input = A heat input-based limit is used for PM. Pollutant-b = Hydrogen chloride is a surrogate for acid gas HAP. HCl-Input = A heat input-based limit is used for hydrogen chloride. Hg-Input-c = A heat input-based limit is used for mercury. Hg LEE Test = LEE Testing is conducted for 30 days. Scrubber/Bypass = The EGU is not equipped with an acid gas scrubber or does not have a main stack and bypass stack exhaust configuration. PM-LEE = The unit is qualifying as a low emitting EGU (LEE) for filterable PM. HCl-LEE = The unit is qualifying as a low emitting EGU (LEE) for hydrogen chloride. Hg-LEE-c = The unit is not qualifying as a low emitting EGU (LEE) for mercury. Startup = Not relying on paragraph (2) definition of “startup” in §63.10042. Compliance Demo = A CEMS (or sorbent trap) is used to demonstrate compliance. Stack Config = Single unit-single stack configuration. O2-CO2 CEMS = An oxygen or carbon dioxide CEMS is used to convert measured pollutant concentrations. Flow Monitor = A stack gas flow rate monitor is used for routine operation of a sorbent trap monitoring system or to convert measured pollutant concentrations. Gas Moisture = Not required to make corrections for stack gas moisture when converting pollutants. Direct HAP = A CEMS or sorbent trap is used to measure HAP directly.	averaging citations specified in 40 CFR Part 63, Subpart UUUUU.
GT1	30 TAC Chapter 117, Utility Electric Generation	R71200	Date Placed in Service = On or before November 15, 1992. Service Type = Gas turbine defined as a peaking unit in 40 CFR § 72.2. Fuel Type = Firing natural gas only. ESAD NOx Emission Limitation = Title 30 TAC §§ 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF). NOx Monitoring System = Monitoring operating parameters in accordance with 40 CFR Part 75, Appendix E. Annual Electric Output = Annual electric output is greater than or equal to the product of 2,500 hours and MW rating of the unit. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). CO Monitoring System = Other than a CEMS or PEMS.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Ammonia Use = Ammonia injection is not used.	
GT1	40 CFR Part 60, Subpart GG	60GG-1	Peak Load Heat Input = Heat Input is greater than 100 MMBtu/hr (107.2 GJ/hr) Construction/Modification Date = On or before October 3, 1977.	
GT1	40 CFR Part 60, Subpart KKKK	60KKKK-1	Unit Type = Simple Combustion Turbine Construction/Modification Date = Turbine was constructed, reconstructed or modified on or before February 18, 2005.	
GT1	40 CFR Part 60, Subpart TTTT	60TTTT-1	Construction/Reconstruction Date = Constructed on or before January 8, 2014	
GT1	40 CFR Part 63, Subpart YYYY	63YYYY-1	Construction/Reconstruction Date = Turbine was constructed, modified or reconstructed on or before 1/14/2003.	
GRP-OWSEP	30 TAC Chapter 115, Water Separation	R5131-1	Alternate Control Requirement = The executive director (or the EPA Administrator) has not approved an ACR or exemption criteria in accordance with 30 TAC § 115.910. Exemption = Any single or multiple compartment VOC water separator which separates materials having a true vapor pressure less than 0.5 psia (3.4 kPa) obtained from any equipment.	
GRP-OWSEP	40 CFR Part 63, Subpart VV	63VV-1	Control = No subpart of 40 CFR Parts 60, 61, or 63 references the use of 40 CFR Part 63, Subpart VV for control of emissions from the separator.	
ENG-168HP	30 TAC Chapter 111, Visible Emissions	R1111-4	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is less than 100,000 actual cubic feet per minute.	
ENG-250HP	30 TAC Chapter 111, Visible Emissions	R1111-5	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is less than 100,000 actual cubic feet per minute.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
ENG-435HP	30 TAC Chapter 111, Visible Emissions	R1111-4	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is less than 100,000 actual cubic feet per minute.	
ENG-44HP	30 TAC Chapter 111, Visible Emissions	R1111-5	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is less than 100,000 actual cubic feet per minute.	
ENG-504HP	30 TAC Chapter 111, Visible Emissions	R1111-5	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is less than 100,000 actual cubic feet per minute.	
ENG-650HP	30 TAC Chapter 111, Visible Emissions	R1111-5	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is less than 100,000 actual cubic feet per minute.	
ENG-765HP	30 TAC Chapter 111, Visible Emissions	R1111-5	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is less than 100,000 actual cubic feet per minute.	
GRP-1-4VENTS	30 TAC Chapter 111, Visible Emissions	R1111-5	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is less than 100,000 actual cubic feet per minute.	
GRP-5VENTS	30 TAC Chapter 111, Visible Emissions	R1111-5	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is less than 100,000 actual cubic feet per minute.	
GRP-6VENTS	30 TAC Chapter 111, Visible Emissions	R1111-5	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is less than 100,000 actual cubic feet per minute.	
GRP-7VENTS	30 TAC Chapter 111, Visible Emissions	R1111-5	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is less than 100,000 actual cubic feet per minute.	
GRP-8VENTS	30 TAC Chapter 111, Visible Emissions	R1111-5	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is less than 100,000 actual cubic feet per minute.	
GRP-B1-2S	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is a steam generator that burns oil or a mixture of oil and gas. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute. SIP Violation = The source is able to comply with applicable PM and opacity regulations without the use of PM collection equipment and has not been found to be in violation of any visible emission standard in a State Implementation Plan.	
GRP-B5-6S	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute. Annual ACF = Annual average capacity factor is less than or equal to 30% as reported to the Federal Power Commission for the calendar year 1974.	
GRP-B5-6S	30 TAC Chapter 111, Visible Emissions	R111-2	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute. Annual ACF = Annual average capacity factor is greater than 30%, as reported to the Federal Power Commission for calendar year 1974 Heat Input = Heat Input is greater than 250 MMBtu/hr.	
SCRUB	30 TAC Chapter 111, Visible Emissions	R1111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute. Annual ACF = Annual average capacity factor is less than or equal to 30% as reported to the Federal Power Commission for the calendar year 1974.	
SCRUB	30 TAC Chapter 111, Visible Emissions	R1111-2	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute. Annual ACF = Annual average capacity factor is greater than 30%, as reported to the Federal Power Commission for calendar year 1974 Heat Input = Heat Input is greater than 250 MMBtu/hr.	
WAP3A	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is a steam generator that burns oil or a mixture of oil and gas. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			SIP Violation = The source is able to comply with applicable PM and opacity regulations without the use of PM collection equipment and has not been found to be in violation of any visible emission standard in a State Implementation Plan.	
WAP3B	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is a steam generator that burns oil or a mixture of oil and gas. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute. SIP Violation = The source is able to comply with applicable PM and opacity regulations without the use of PM collection equipment and has not been found to be in violation of any visible emission standard in a State Implementation Plan.	
WAP4	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAP7	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute. Annual ACF = Annual average capacity factor is less than or equal to 30% as reported to the Federal Power Commission for the calendar year 1974.	
WAP7	30 TAC Chapter 111, Visible Emissions	R111-2	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C).	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute. Annual ACF = Annual average capacity factor is greater than 30%, as reported to the Federal Power Commission for calendar year 1974 Heat Input = Heat Input is greater than 250 MMBtu/hr.	
WAP8	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute. Annual ACF = Annual average capacity factor is less than or equal to 30% as reported to the Federal Power Commission for the calendar year 1974.	
WAP8	30 TAC Chapter 111, Visible Emissions	R111-2	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute. Annual ACF = Annual average capacity factor is greater than 30%, as reported to the Federal Power Commission for calendar year 1974 Heat Input = Heat Input is greater than 250 MMBtu/hr.	
WAPAB	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAPACT5	30 TAC Chapter 111, Visible Emissions	R1111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAPACT6	30 TAC Chapter 111, Visible Emissions	R1111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAPACT7	30 TAC Chapter 111, Visible Emissions	R1111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAPACT8	30 TAC Chapter 111, Visible Emissions	R1111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAPAUX1-4	30 TAC Chapter 111, Visible Emissions	R1111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAPGT1	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAPMCT7	30 TAC Chapter 111, Visible Emissions	R1111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAPMCT8	30 TAC Chapter 111, Visible Emissions	R1111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
GRP-DEG	30 TAC Chapter 115, Degreasing Processes	R5412-1	Solvent Degreasing Machine Type = Remote reservoir cold solvent cleaning machine. Solvent Sprayed = No solvent is sprayed. Solvent Vapor Pressure = Solvent vapor pressure is less than or equal to 0.6 psia as measured at 100 degrees Fahrenheit. Solvent Heated = The solvent is not heated to a temperature greater than 120 degrees Fahrenheit	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Parts Larger than Drainage = No cleaned parts for which the machine is authorized to clean are larger than the internal drainage facility of the machine. Drainage Area = Area is less than 16 square inches. Disposal in Enclosed Containers = Waste solvent is properly disposed of in enclosed containers.	
GRP-5&6CL	40 CFR Part 60, Subpart Y	60Y-1	Affected Facility = Coal processing and conveying equipment (including breakers and crushers), coal storage systems (excluding open storage piles), or coal transfer and loading systems Construction/Reconstruction/Modification Date = After October 24, 1974 and before April 28, 2008.	
GRP-7&8CL	40 CFR Part 60, Subpart Y	60Y-1	Affected Facility = Coal processing and conveying equipment (including breakers and crushers), coal storage systems (excluding open storage piles), or coal transfer and loading systems Construction/Reconstruction/Modification Date = After October 24, 1974 and before April 28, 2008.	

* - The “unit attributes” or operating conditions that determine what requirements apply
** - Notes changes made to the automated results from the DSS, and a brief explanation why

NSR Versus Title V FOP

The state of Texas has two Air permitting programs, New Source Review (NSR) and Title V Federal Operating Permits. The two programs are substantially different both in intent and permit content.

NSR is a preconstruction permitting program authorized by the Texas Clean Air Act and Title I of the Federal Clean Air Act (FCAA). The processing of these permits is governed by 30 Texas Administrative Code (TAC) Chapter 116.111. The Title V Federal Operating Program is a federal program authorized under Title V of the FCAA that has been delegated to the state of Texas to administer and is governed by 30 TAC Chapter 122. The major differences between the two permitting programs are listed in the table below:

NSR Permit	Federal Operating Permit (FOP)
Issued Prior to new Construction or modification of an existing facility	For initial permit with application shield, can be issued after operation commences; significant revisions require approval prior to operation.
Authorizes air emissions	Codifies existing applicable requirements, does not authorize new emissions
Ensures issued permits are protective of the environment and human health by conducting a health effects review and that requirement for best available control technology (BACT) is implemented.	Applicable requirements listed in permit are used by the inspectors to ensure proper operation of the site as authorized. Ensures that adequate monitoring is in place to allow compliance determination with the FOP.
Up to two Public notices may be required. Opportunity for public comment and contested case hearings for some authorizations.	One public notice required. Opportunity for public comments. No contested case hearings.
Applies to all point source emissions in the state.	Applies to all major sources and some non-major sources identified by the EPA.
Applies to facilities: a portion of site or individual emission sources	One or multiple FOPs cover the entire site (consists of multiple facilities)
Permits include terms and conditions under which the applicant must construct and operate its various equipment and processes on a facility basis.	Permits include terms and conditions that specify the general operational requirements of the site; and include codification of all applicable requirements for emission units at the site.
Opportunity for EPA review for Federal Prevention of Significant Deterioration (PSD) and Nonattainment (NA) permits for major sources.	Opportunity for EPA review, affected states review, and a Public petition period for every FOP.
Permits have a table listing maximum emission limits for pollutants	Permit has an applicable requirements table and Periodic Monitoring (PM) / Compliance Assurance Monitoring (CAM) tables which document applicable monitoring requirements.
Permits can be altered or amended upon application by company. Permits must be issued before construction or modification of facilities can begin.	Permits can be revised through several revision processes, which provide for different levels of public notice and opportunity to comment. Changes that would be significant revisions require that a revised permit be issued before those changes can be operated.
NSR permits are issued independent of FOP requirements.	FOPs are independent of NSR permits, but contain a list of all NSR permits incorporated by reference

New Source Review Requirements

Below is a list of the New Source Review (NSR) permits for the permitted area. These NSR permits are incorporated by reference into the operating permit and are enforceable under it. These permits can be found in the main TCEQ file room, located on the first floor of Building E, 12100 Park 35 Circle, Austin, Texas. In addition, many of the permits are accessible online through the link provided below. The Public Education Program may be contacted at 1-800-687-4040 or the Air Permits Division (APD) may be contacted at 1-512-239-1250 for help with any question.

Additionally, the site contains emission units that are permitted by rule under the requirements of 30 TAC Chapter 106, Permits by Rule. Permit by Rule (PBR) registrations submitted by permittees are also available online through the link provided below. The following table specifies the PBRs that apply to the site.

The status of air permits, applications, and PBR registrations may be found by performing the appropriate search of the databases located at the following website:

www.tceq.texas.gov/permitting/air/nav/air_status_permits.html

Details on how to search the databases are available in the **Obtaining Permit Documents** section below.

New Source Review Authorization References

Prevention of Significant Deterioration (PSD) Permits	
PSD Permit No.: PSDTX234M2	Issuance Date: 08/23/2021
PSD Permit No.: PSDTX33M1	Issuance Date: 07/18/2016
PSD Permit No.: PSDTX901	Issuance Date: 02/08/2016
PSD Permit No.: PSDTX902	Issuance Date: 02/25/2016
Nonattainment (NA) Permits	
NA Permit No.: N033	Issuance Date: 02/08/2016
NA Permit No.: N034	Issuance Date: 02/25/2016
NA Permit No.: N035	Issuance Date: 07/18/2016
Title 30 TAC Chapter 116 Permits, Special Permits, and Other Authorizations (Other Than Permits by Rule, PSD Permits, or NA Permits) for the Application Area.	
Authorization No.: 2348A	Issuance Date: 02/08/2016
Authorization No.: 2349A	Issuance Date: 02/25/2016
Authorization No.: 4130A	Issuance Date: 05/20/2016
Authorization No.: 5126	Issuance Date: 02/04/2016
Authorization No.: 5530	Issuance Date: 07/18/2016
Authorization No.: 7704	Issuance Date: 08/23/2021
Authorization No.: 7706A	Issuance Date: 05/20/2016
Authorization No.: 18851	Issuance Date: 11/04/2015
Authorization No.: 39571	Issuance Date: 06/15/2018
Authorization No.: 39729	Issuance Date: 04/27/2018
Authorization No.: 40542	Issuance Date: 04/27/2018
Authorization No.: 43191	Issuance Date: 04/11/2019
Authorization No.: 45326	Issuance Date: 05/13/2020
Authorization No.: 45575	Issuance Date: 06/15/2022
Authorization No.: 45779	Issuance Date: 05/13/2020
Authorization No.: 46599	Issuance Date: 05/18/2020
Authorization No.: 72347	Issuance Date: 12/14/2022
Authorization No.: 97958	Issuance Date: 08/27/2020
Authorization No.: 104887	Issuance Date: 07/28/2021
Authorization No.: 108189	Issuance Date: 02/04/2022

New Source Review Authorization References

Authorization No.: 152549	Issuance Date: 07/19/2018
Permits by Rule (30 TAC Chapter 106) for the Application Area	
Number: 106.124	Version No./Date: 09/04/2000
Number: 106.263	Version No./Date: 11/01/2001
Number: 106.433	Version No./Date: 03/14/1997
Number: 106.452	Version No./Date: 09/04/2000
Number: 106.454	Version No./Date: 11/01/2001
Number: 106.472	Version No./Date: 09/04/2000
Number: 106.473	Version No./Date: 09/04/2000
Number: 106.512	Version No./Date: 06/13/2001
Number: 5	Version No./Date: 06/07/1996
Number: 8	Version No./Date: 06/07/1996
Number: 14	Version No./Date: 11/05/1986
Number: 14	Version No./Date: 08/30/1988
Number: 14	Version No./Date: 09/12/1989
Number: 14	Version No./Date: 06/07/1996
Number: 34	Version No./Date: 06/07/1996
Number: 39	Version No./Date: 06/07/1996
Number: 40	Version No./Date: 06/07/1996
Number: 51	Version No./Date: 08/30/1988
Number: 51	Version No./Date: 06/07/1996
Number: 53	Version No./Date: 06/07/1996
Number: 61	Version No./Date: 11/05/1986
Number: 61	Version No./Date: 06/07/1996
Number: 70	Version No./Date: 06/07/1996
Number: 75	Version No./Date: 06/07/1996
Number: 83	Version No./Date: 06/07/1996
Number: 84	Version No./Date: 11/25/1985
Number: 102	Version No./Date: 06/07/1996
Number: 103	Version No./Date: 06/07/1996
Number: 107	Version No./Date: 06/07/1996

Permits by Rule

The TCEQ has interpreted the emission limits prescribed in 30 TAC §106.4(a) as both emission thresholds and default emission limits. The emission limits in 30 TAC §106.4(a) are all considered applicable to each facility as a threshold matter to ensure that the owner/operator qualifies for the PBR authorization. Those same emission limits are also the default emission limits if the specific PBR does not further limit emissions or there is no lower, certified emission limit claimed by the owner/operator.

This interpretation is consistent with how TCEQ has historically determined compliance with the emission limits prior to the addition of the "as applicable" language. The "as applicable" language was added in 2014 as part of changes to the sentence structure in a rulemaking that made other changes to address greenhouse gases and was not intended as a substantive rule change. This interpretation also provides for effective and practical enforcement of 30 TAC §106.4(a), since for the TCEQ to effectively enforce the emission limits in 30 TAC §106.4(a) as emission thresholds, all emission limits must apply. As provided by 30 TAC §106.4(a)(2) and (3), an owner/operator shall not claim a PBR authorization if the facility is subject to major New Source Review. The practical and legal effect of the language in 30 TAC § 106.4 is that if a facility does not emit a pollutant, then the potential to emit for that particular pollutant is zero, and thus, the facility is not authorized to emit the pollutant pursuant to the PBR.

The permit holder is required to keep records for demonstrating compliance with PBRs in accordance with 30 TAC § 106.8 for the following categories:

- As stated in 30 TAC § 106.8(a), the permit holder is not required to keep records for de minimis sources as designated in 30 TAC § 116.119.
- As stated in 30 TAC § 106.8(b) for PBRs on the insignificant activities list, the permit holder is required to provide information that would demonstrate compliance with the general requirements of 30 TAC § 106.4.
- As stated in 30 TAC § 106.8(c) for all other PBRs, the permit holder must maintain sufficient records to demonstrate compliance with the general requirements specified in 30 TAC § 106.4 and to demonstrate compliance with the emission limits and any specific conditions of the PBR as applicable.

The application, or a previously submitted application, contains a PBR Supplemental Table. This table provides supplemental information for all PBR authorizations at the site or application area, including PBRs that are not listed on the OP-REQ1 form. PBRs that are not listed on the OP-REQ1 form authorize emission units that the TCEQ has determined are insignificant sources of emissions (IEUs). PBRs are enforceable through permit condition number **11**. The EPA gives States broad discretion in prescribing monitoring, recordkeeping, and reporting for generally applicable requirements that cover insignificant emission units. (see EPA *White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program*). Federal regulations specifically identify recordkeeping as an appropriate level of monitoring necessary to assure compliance with the requirements applicable to an emissions unit. Permitting authorities have the best sense of where it is appropriate to conclude that periodic monitoring is not necessary for IEUs, when state program rules already provide sufficient monitoring for these units.

In the case of IEUs in particular, the recordkeeping in 30 TAC §106.8 is sufficient because the units do not have the potential to violate emission limitations or other requirements under normal operating conditions. In particular, where the establishment of a regular program of monitoring would not significantly enhance the ability of the permit to assure compliance with the applicable requirement, the permitting authority can provide that the applicable requirement has monitoring sufficient to yield reliable data that is representative of the emission unit's compliance with the limitations. Therefore, for IEUs compliance with 30 TAC §106.8 is sufficient to meet federal monitoring requirements.

The PBR records may include, but are not limited to, production capacity and throughput, hours of operation, safety data sheets (SDS), chemical composition of raw materials, speciation of air contaminant data, engineering calculations, maintenance records, fugitive data, performance tests, capture/control device efficiencies, or parametric monitoring. The PBR records also satisfy the federal operating permit periodic monitoring requirements of 30 TAC § 122.142(c) as they are representative of the emission unit's compliance with 30 TAC Chapter 106.

Emission Units and Emission Points

In air permitting terminology, any source capable of generating emissions (for example, an engine or a sandblasting area) is called an Emission Unit. For purposes of Title V, emission units are specifically listed in the operating permit when they have applicable requirements other than New Source Review (NSR), or when they are listed in the permit shield table.

The actual physical location where the emissions enter the atmosphere (for example, an engine stack or a sand-blasting yard) is called an emission point. For New Source Review preconstruction permitting purposes, every emission unit has an associated emission point. Emission limits are listed in an NSR permit, associated with an emission point. This list of emission points and emission limits per pollutant is commonly referred to as the "Maximum Allowable Emission Rate Table", or "MAERT" for short. Specifically, the MAERT lists the Emission Point Number (EPN) that identifies the emission point, followed immediately by the Source Name, identifying the emission unit that is the source of those emissions on this table.

Thus, by reference, an emission unit in a Title V operating permit is linked by reference number to an NSR authorization, and its related emission point.

Monitoring Sufficiency

Federal and state rules, 40 CFR § 70.6(a)(3)(i)(B) and 30 TAC § 122.142(c) respectively, require that each federal operating permit include additional monitoring for applicable requirements that lack periodic or instrumental monitoring (which may include recordkeeping that serves as monitoring) that yields reliable data from a relevant time period that are representative of the emission unit's compliance with the applicable emission limitation or standard. Furthermore, the federal operating permit must include compliance assurance monitoring (CAM) requirements for emission sources that meet the applicability criteria of 40 CFR Part 64 in accordance with 40 CFR § 70.6(a)(3)(i)(A) and 30 TAC § 122.604(b).

With the exception of any emission units listed in the Periodic Monitoring or CAM Summaries in the FOP, the TCEQ Executive Director has determined that the permit contains sufficient monitoring, testing, recordkeeping, and reporting requirements that assure compliance with the applicable requirements. If applicable, each emission unit that requires additional monitoring in the form of periodic monitoring or CAM is described in further detail under the Rationale for CAM/PM Methods Selected section following this paragraph.

Rationale for Compliance Assurance Monitoring (CAM)/ Periodic Monitoring Methods Selected

Compliance Assurance Monitoring (CAM):

Compliance Assurance Monitoring (CAM) is a federal monitoring program established under Title 40 Code of Federal Regulations Part 64 (40 CFR Part 64).

Emission units are subject to CAM requirements if they meet the following criteria:

1. the emission unit is subject to an emission limitation or standard for an air pollutant (or surrogate thereof) in an applicable requirement;

2. the emission unit uses a control device to achieve compliance with the emission limitation or standard specified in the applicable requirement; and

3. the emission unit has the pre-control device potential to emit greater than or equal to the amount in tons per year for a site to be classified as a major source.

The following table(s) identify the emission unit(s) that are subject to CAM:

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Nonagricultural Processes	SOP Index No.: R1151-3
Pollutant: PM	Main Standard: § 111.153(b)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Maximum Opacity = 10% averaged over a six minute period during normal operations; Maximum Opacity = 20% averaged over a six minute period during maintenance, startup, and shutdown.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-1
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-1
Pollutant: PM (Opacity)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-2
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-2
Pollutant: PM (Opacity)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-3
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-3
Pollutant: PM (Opacity)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-4
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA’s “Compliance Assurance Monitoring (CAM) Technical Guidance Document” (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA’s Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to “EPA Reference Method 22” procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-4
Pollutant: PM (Opacity)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-5
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-5
Pollutant: PM (Opacity)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-6
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-6
Pollutant: PM (Opacity)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Nonagricultural Processes	SOP Index No.: R1151-3
Pollutant: PM	Main Standard: § 111.153(b)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Maximum Opacity = 10% averaged over a six minute period during normal operations; Maximum Opacity = 20% averaged over a six minute period during maintenance, startup, and shutdown.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Other control device type
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: REG2-1
Pollutant: SO_2	Main Standard: § 112.8(a)
Monitoring Information	
Indicator: Sulfur Dioxide Concentration	
Minimum Frequency: four times per hour	
Averaging Period: one hour	
Deviation Limit: Emissions of SO2 from any solid fossil fuel-fired steam generator shall not exceed 3.0 pounds per million Btu (MMBtu) heat input averaged over a three hour period.	
Basis of CAM: It is widely practiced and accepted to calibrate and use a portable analyzer or CEMS to measure SO2 concentration with procedures such as EPA Test Method 6C. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: 60Da-1
Pollutant: PM	Main Standard: § 60.42Da(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: 60Da-2
Pollutant: PM	Main Standard: § 60.42Da(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: 60Da-3
Pollutant: PM	Main Standard: § 60.42Da(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: 60Da-4
Pollutant: PM	Main Standard: § 60.42Da(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: 60Da-5
Pollutant: PM	Main Standard: § 60.42Da(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: 60Da-6
Pollutant: PM	Main Standard: § 60.42Da(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: 60Da-7
Pollutant: PM	Main Standard: § 60.42Da(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Nonagricultural Processes	SOP Index No.: R1151-3
Pollutant: PM	Main Standard: § 111.153(b)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Maximum Opacity = 10% averaged over a six minute period during normal operations; Maximum Opacity = 20% averaged over a six minute period during maintenance, startup, and shutdown.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-1
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-1
Pollutant: PM (Opacity)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-2
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-2
Pollutant: PM (Opacity)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-3
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: Fabric filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-3
Pollutant: PM (Opacity)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Periodic Monitoring:

The Federal Clean Air Act requires that each federal operating permit include monitoring sufficient to assure compliance with the terms and conditions of the permit. Most of the emission limits and standards applicable to emission units at Title V sources include adequate monitoring to show that the units meet the limits and standards. For those requirements that do not include monitoring, or where the monitoring is not sufficient to assure compliance, the federal operating permit must include such monitoring for the emission units affected. The following emission units are subject to periodic monitoring requirements because the emission units are subject to an emission limitation or standard for an air pollutant (or surrogate thereof) in an applicable requirement that does not already require monitoring, or the monitoring for the applicable requirement is not sufficient to assure compliance:

Unit/Group/Process Information	
ID No.: 3	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: REG2-1
Pollutant: SO_2	Main Standard: § 112.9(a)
Monitoring Information	
Indicator: Sulfur Content of Fuel	
Minimum Frequency: Quarterly and within 24 hours of any fuel change	
Averaging Period: n/a	
Deviation Limit: Emissions of SO2 from any liquid fuel-fired steam generator, furnace, or heater shall not exceed 440 ppmv at actual stack conditions and averaged over a three-hour period.	
Basis of monitoring: A common way to determine SO2 emissions is by determining the amount (percentage) of sulfur in fuel combusted by an emission unit. This quantity along with stack flow rate and quantity of fuel combusted may be used to calculate the amount of SO2 emitted to the atmosphere.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: REG2-1
Pollutant: SO_2	Main Standard: § 112.8(a)
Monitoring Information	
Indicator: SO2 Concentration	
Minimum Frequency: Four times per hour	
Averaging Period: Hourly	
Deviation Limit: Any monitoring data above the maximum limit of 3.0 lb/MMBtu averaged over a three-hour period shall be considered and reported as a deviation.	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or CEMS to measure SO2 concentration with procedures such as EPA Test Method 6C. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: REG2-2
Pollutant: SO_2	Main Standard: § 112.9(a)
Monitoring Information	
Indicator: SO2 Concentration	
Minimum Frequency: Four times per hour	
Averaging Period: Hourly	
Deviation Limit: Any monitoring data above the maximum limit of 400 ppmv averaged over a three-hour period shall be considered and reported as a deviation.	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or CEMS to measure SO2 concentration with procedures such as EPA Test Method 6C. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-2
Pollutant: NH_3	Main Standard: § 117.1210(b)(2)
Monitoring Information	
Indicator: NH3 Concentration	
Minimum Frequency: Annually (Calendar Year)	
Averaging Period: n/a	
Deviation Limit: Maximum NH3 = 10 ppmv on a one-hour average	
Basis of monitoring: It is widely practiced and accepted to use stack testing to measure pollutants from emission sources. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Specifically, EPA has validated Conditional Test Method 027 - "Procedure for Collection and Analysis of Ammonia in Stationary Sources" for use with coal-fired boilers in power plants.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-7
Pollutant: CO	Main Standard: [G]§ 117.1225(a)
Monitoring Information	
Indicator: CO Concentration	
Minimum Frequency: four times per hour	
Averaging Period: one hour	
Deviation Limit: Maximum CO = 1,891 lb/hr, 24-hour avg (while firing coal only) or 1,973 lb/hr, 24-hour avg (while firing coal and supplementing with natural gas)	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer to measure CO concentration with procedures such as EPA Test Method 10 or a CO CEMS. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. In addition, if the CO concentration is too high it shows that a control device such as a catalytic converter is not functioning properly or an emission unit is not obtaining complete combustion.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-7
Pollutant: NH_3	Main Standard: [G]§ 117.1225(a)
Monitoring Information	
Indicator: Planned unit startup and shutdown durations	
Minimum Frequency: Each planned startup and shutdown	
Averaging Period: n/a	
Deviation Limit: Planned unit startup and shutdown durations not to exceed those defined in NSR permit 5530/PSDTX33M1/N035.	
Basis of monitoring: NH3 emissions authorized by the NSR permit were calculated using stack flow, annual operating hours, and ammonia concentrations from stack tests, with the assumption that NH3 is injected during all periods of boiler operation. Therefore, the duration of each planned startup and shutdown can be used to determine the portion of NH3 emissions that results from those activities. Records of each planned startup and shutdown duration will be used to calculate NH3 emissions on a monthly basis as required in the NSR permit, and meeting the duration limits in the NSR permit will ensure that the NH3 emission limits are not exceeded.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-1
Pollutant: NO_X	Main Standard: § 60.44(a)(1)
Monitoring Information	
Indicator: NOx Concentration	
Minimum Frequency: Four times per hour	
Averaging Period: One hour	
Deviation Limit: No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NOx, expressed as NO2 in excess of 0.20 lb NOx/MMBtu.	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or NOx CEMS/PEMS to measure NOx concentration with procedures such as EPA Test Method 7. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Additionally, measuring the NOx concentration is provided as a monitoring option for any control device because an increase in NOx concentration may be indicative of the control device performance. Outlet NOx concentration has been used as an indicator in many federal and state rules.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-2
Pollutant: NO_X	Main Standard: § 60.44(a)(3)
Monitoring Information	
Indicator: NOx Concentration	
Minimum Frequency: Four times per hour	
Averaging Period: One hour	
Deviation Limit: No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NOx, expressed as NO2 in excess of 0.70 lb NOx/MMBtu.	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or NOx CEMS/PEMS to measure NOx concentration with procedures such as EPA Test Method 7. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Additionally, measuring the NOx concentration is provided as a monitoring option for any control device because an increase in NOx concentration may be indicative of the control device performance. Outlet NOx concentration has been used as an indicator in many federal and state rules.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-3
Pollutant: NO_X	Main Standard: § 60.44(b)
Monitoring Information	
Indicator: NOx Concentration	
Minimum Frequency: Four times per hour	
Averaging Period: One hour	
Deviation Limit: No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NOx, expressed as NO2 in excess of 0.70 lb NOx/MMBtu.	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or NOx CEMS/PEMS to measure NOx concentration with procedures such as EPA Test Method 7. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Additionally, measuring the NOx concentration is provided as a monitoring option for any control device because an increase in NOx concentration may be indicative of the control device performance. Outlet NOx concentration has been used as an indicator in many federal and state rules.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-4
Pollutant: NO_X	Main Standard: § 60.44(b)
Monitoring Information	
Indicator: NOx Concentration	
Minimum Frequency: Four times per hour	
Averaging Period: One hour	
Deviation Limit: No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NOx, expressed as NO2 in excess of 0.30 lb NOx/MMBtu.	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or NOx CEMS/PEMS to measure NOx concentration with procedures such as EPA Test Method 7. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Additionally, measuring the NOx concentration is provided as a monitoring option for any control device because an increase in NOx concentration may be indicative of the control device performance. Outlet NOx concentration has been used as an indicator in many federal and state rules.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-5
Pollutant: NO_X	Main Standard: § 60.44(b)
Monitoring Information	
Indicator: NOx Concentration	
Minimum Frequency: Four times per hour	
Averaging Period: One hour	
Deviation Limit: No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NOx, expressed as NO2 in excess of 0.70 lb NOx/MMBtu.	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or NOx CEMS/PEMS to measure NOx concentration with procedures such as EPA Test Method 7. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Additionally, measuring the NOx concentration is provided as a monitoring option for any control device because an increase in NOx concentration may be indicative of the control device performance. Outlet NOx concentration has been used as an indicator in many federal and state rules.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-6
Pollutant: NO_X	Main Standard: § 60.44(b)
Monitoring Information	
Indicator: NOx Concentration	
Minimum Frequency: Four times per hour	
Averaging Period: One hour	
Deviation Limit: No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NOx, expressed as NO2 in excess of 0.70 lb NOx/MMBtu.	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or NOx CEMS/PEMS to measure NOx concentration with procedures such as EPA Test Method 7. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Additionally, measuring the NOx concentration is provided as a monitoring option for any control device because an increase in NOx concentration may be indicative of the control device performance. Outlet NOx concentration has been used as an indicator in many federal and state rules.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-2
Pollutant: NH_3	Main Standard: § 117.1210(b)(2)
Monitoring Information	
Indicator: NH3 Concentration	
Minimum Frequency: Annually (Calendar Year)	
Averaging Period: n/a	
Deviation Limit: Maximum NH3 = 10 ppmv on a one-hour average	
Basis of monitoring: It is widely practiced and accepted to use stack testing to measure pollutants from emission sources. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Specifically, EPA has validated Conditional Test Method 027 - "Procedure for Collection and Analysis of Ammonia in Stationary Sources" for use with coal-fired boilers in power plants.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-8
Pollutant: CO	Main Standard: [G]§ 117.1225(a)
Monitoring Information	
Indicator: CO Concentration	
Minimum Frequency: four times per hour	
Averaging Period: one hour	
Deviation Limit: Maximum CO = 2,010 lb/hr, 24-hour avg	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer to measure CO concentration with procedures such as EPA Test Method 10 or a CO CEMS. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. In addition, if the CO concentration is too high it shows that a control device such as a catalytic converter is not functioning properly or an emission unit is not obtaining complete combustion.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-8
Pollutant: NH_3	Main Standard: [G]§ 117.1225(a)
Monitoring Information	
Indicator: Planned unit startup and shutdown durations	
Minimum Frequency: Each planned startup and shutdown	
Averaging Period: n/a	
Deviation Limit: Planned unit startup and shutdown durations not to exceed those defined in NSR permit 7704/PSDTX234M2.	
Basis of monitoring: NH3 emissions authorized by the NSR permit were calculated using stack flow, annual operating hours, and ammonia concentrations from stack tests, with the assumption that NH3 is injected during all periods of boiler operation. Therefore, the duration of each planned startup and shutdown can be used to determine the portion of NH3 emissions that results from those activities. Records of each planned startup and shutdown duration will be used to calculate NH3 emissions on a monthly basis as required in the NSR permit, and meeting the duration limits in the NSR permit will ensure that the NH3 emission limits are not exceeded.	

Unit/Group/Process Information	
ID No.: ENG-168HP	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-4
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(A)
Monitoring Information	
Indicator: Visible Emissions	
Minimum Frequency: once per calendar quarter	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 30% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations. The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: ENG-250HP	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-5
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(B)
Monitoring Information	
Indicator: Visible Emissions	
Minimum Frequency: once per calendar quarter	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 20% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations. The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: ENG-435HP	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-4
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(A)
Monitoring Information	
Indicator: Visible Emissions	
Minimum Frequency: once per calendar quarter	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 30% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations. The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: ENG-44HP	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-5
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(B)
Monitoring Information	
Indicator: Visible Emissions	
Minimum Frequency: once per calendar quarter	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 20% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations. The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: ENG-504HP	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-5
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(B)
Monitoring Information	
Indicator: Visible Emissions	
Minimum Frequency: once per calendar quarter	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 20% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations. The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: ENG-650HP	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-5
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(B)
Monitoring Information	
Indicator: Visible Emissions	
Minimum Frequency: once per calendar quarter	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 20% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations. The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: ENG-765HP	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-5
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(B)
Monitoring Information	
Indicator: Visible Emissions	
Minimum Frequency: once per calendar quarter	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 20% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations. The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-1-4VENTS	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-5
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(B)
Monitoring Information	
Indicator: Visible emissions	
Minimum Frequency: Annually	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 20% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures. Historically, the lube oil vents associated with the boilers at W. A. Parish Electric Generating Station have consistently been in compliance with the opacity standards under 30 TAC Chapter 111. Past observations have generally resulted in no visible emissions, with the exception of occasional water vapor. Therefore, it is expected that the likelihood of a violation of the 20% opacity standard for the lube oil vents is extremely low. The emissions from these lube oil vents, as well as the variability of emissions, are both extremely low; the lube oil vents are only in operation while the combustion turbines are in operation. Furthermore, operation of the lube oil vents is consistent across all turbine operation, regardless of the load. The only variability that exists would come from the ambient temperature, which may affect the presence of water vapor coming from the source.	

Unit/Group/Process Information	
ID No.: GRP-5&6CL	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Y	SOP Index No.: 60Y-1
Pollutant: PM (Opacity)	Main Standard: § 60.254(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: Once per month	
Averaging Period: Six-minutes	
Deviation Limit: It shall be considered a deviation if the maximum opacity is 20% or greater.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-5VENTS	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-5
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(B)
Monitoring Information	
Indicator: Visible emissions	
Minimum Frequency: Annually	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 20% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures. Historically, the lube oil vents associated with the boilers at W. A. Parish Electric Generating Station have consistently been in compliance with the opacity standards under 30 TAC Chapter 111. Past observations have generally resulted in no visible emissions, with the exception of occasional water vapor. Therefore, it is expected that the likelihood of a violation of the 20% opacity standard for the lube oil vents is extremely low. The emissions from these lube oil vents, as well as the variability of emissions, are both extremely low; the lube oil vents are only in operation while the combustion turbines are in operation. Furthermore, operation of the lube oil vents is consistent across all turbine operation, regardless of the load. The only variability that exists would come from the ambient temperature, which may affect the presence of water vapor coming from the source.	

Unit/Group/Process Information	
ID No.: GRP-6VENTS	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-5
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(B)
Monitoring Information	
Indicator: Visible emissions	
Minimum Frequency: Annually	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 20% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures. Historically, the lube oil vents associated with the boilers at W. A. Parish Electric Generating Station have consistently been in compliance with the opacity standards under 30 TAC Chapter 111. Past observations have generally resulted in no visible emissions, with the exception of occasional water vapor. Therefore, it is expected that the likelihood of a violation of the 20% opacity standard for the lube oil vents is extremely low. The emissions from these lube oil vents, as well as the variability of emissions, are both extremely low; the lube oil vents are only in operation while the combustion turbines are in operation. Furthermore, operation of the lube oil vents is consistent across all turbine operation, regardless of the load. The only variability that exists would come from the ambient temperature, which may affect the presence of water vapor coming from the source.	

Unit/Group/Process Information	
ID No.: GRP-7&8CL	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Y	SOP Index No.: 60Y-1
Pollutant: PM (Opacity)	Main Standard: § 60.254(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: Once per month	
Averaging Period: Six-minutes	
Deviation Limit: It shall be considered a deviation if the maximum opacity is 20% or greater.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-7VENTS	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-5
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(B)
Monitoring Information	
Indicator: Visible emissions	
Minimum Frequency: Annually	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 20% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures. Historically, the lube oil vents associated with the boilers at W. A. Parish Electric Generating Station have consistently been in compliance with the opacity standards under 30 TAC Chapter 111. Past observations have generally resulted in no visible emissions, with the exception of occasional water vapor. Therefore, it is expected that the likelihood of a violation of the 20% opacity standard for the lube oil vents is extremely low. The emissions from these lube oil vents, as well as the variability of emissions, are both extremely low; the lube oil vents are only in operation while the combustion turbines are in operation. Furthermore, operation of the lube oil vents is consistent across all turbine operation, regardless of the load. The only variability that exists would come from the ambient temperature, which may affect the presence of water vapor coming from the source.	

Unit/Group/Process Information	
ID No.: GRP-8VENTS	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-5
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(B)
Monitoring Information	
Indicator: Visible emissions	
Minimum Frequency: Annually	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 20% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures. Historically, the lube oil vents associated with the boilers at W. A. Parish Electric Generating Station have consistently been in compliance with the opacity standards under 30 TAC Chapter 111. Past observations have generally resulted in no visible emissions, with the exception of occasional water vapor. Therefore, it is expected that the likelihood of a violation of the 20% opacity standard for the lube oil vents is extremely low. The emissions from these lube oil vents, as well as the variability of emissions, are both extremely low; the lube oil vents are only in operation while the combustion turbines are in operation. Furthermore, operation of the lube oil vents is consistent across all turbine operation, regardless of the load. The only variability that exists would come from the ambient temperature, which may affect the presence of water vapor coming from the source.	

Unit/Group/Process Information	
ID No.: GRP-B1-2	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: REG2-1
Pollutant: SO_2	Main Standard: § 112.9(a)
Monitoring Information	
Indicator: Sulfur Content of Fuel	
Minimum Frequency: Quarterly and within 24 hours of any fuel change	
Averaging Period: n/a	
Deviation Limit: Emissions of SO2 from any liquid fuel-fired steam generator, furnace, or heater shall not exceed 440 ppmv at actual stack conditions and averaged over a three-hour period.	
Basis of monitoring: A common way to determine SO2 emissions is by determining the amount (percentage) of sulfur in fuel combusted by an emission unit. This quantity along with stack flow rate and quantity of fuel combusted may be used to calculate the amount of SO2 emitted to the atmosphere.	

Unit/Group/Process Information	
ID No.: GRP-B1-2S	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Fuel Type	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
Deviation Limit: If alternative fuel is fired for > 24 consecutive hours, report as a deviation, or conduct observation using Test Method 22. Report as a deviation if visible emissions are observed using Test Method 22 and opacity > 15% using Test Method 9.	
Basis of monitoring: Industry has demonstrated through performance tests and historical data that opacity and particulate matter standards are consistently met when combustion units fire natural gas only. If the emission unit fires a different fuel for more than 24 hours, the permit holder may elect to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: FABRIC FILTER
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: REG2-1
Pollutant: SO_2	Main Standard: § 112.8(a)
Monitoring Information	
Indicator: SO2 Concentration	
Minimum Frequency: Four times per hour	
Averaging Period: Hourly	
Deviation Limit: Any monitoring data above the maximum limit of 3.0 lb/MMBtu averaged over a three-hour period shall be considered and reported as a deviation.	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or CEMS to measure SO2 concentration with procedures such as EPA Test Method 6C. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: FABRIC FILTER
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-2
Pollutant: NH_3	Main Standard: § 117.1210(b)(2)
Monitoring Information	
Indicator: NH3 Concentration	
Minimum Frequency: Annually (Calendar Year)	
Averaging Period: n/a	
Deviation Limit: Maximum NH3 = 10 ppmv on a one-hour average	
Basis of monitoring: It is widely practiced and accepted to use stack testing to measure pollutants from emission sources. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Specifically, EPA has validated Conditional Test Method 027 - "Procedure for Collection and Analysis of Ammonia in Stationary Sources" for use with coal-fired boilers in power plants.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: FABRIC FILTER
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-4
Pollutant: CO	Main Standard: [G]§ 117.1225(a)
Monitoring Information	
Indicator: CO Concentration	
Minimum Frequency: four times per hour	
Averaging Period: one hour	
Deviation Limit: Maximum CO = 2,168 lb/hr, 24-hour avg (while firing coal only) or 2,238 lb/hr, 24-hour avg (while firing coal and supplementing with natural gas)	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer to measure CO concentration with procedures such as EPA Test Method 10 or a CO CEMS. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. In addition, if the CO concentration is too high it shows that a control device such as a catalytic converter is not functioning properly or an emission unit is not obtaining complete combustion.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: FABRIC FILTER
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-4
Pollutant: NH_3	Main Standard: [G]§ 117.1225(a)
Monitoring Information	
Indicator: Planned unit startup and shutdown durations	
Minimum Frequency: Each planned startup and shutdown	
Averaging Period: n/a	
Deviation Limit: Planned unit startup and shutdown durations not to exceed those defined in NSR permit 2348A/PSDTX901/N033 (Unit 5) and NSR permit 2349A/PSDTX902/N034 (Unit 6).	
Basis of monitoring: NH3 emissions authorized by the NSR permit were calculated using stack flow, annual operating hours, and ammonia concentrations from stack tests, with the assumption that NH3 is injected during all periods of boiler operation. Therefore, the duration of each planned startup and shutdown can be used to determine the portion of NH3 emissions that results from those activities. Records of each planned startup and shutdown duration will be used to calculate NH3 emissions on a monthly basis as required in the NSR permit, and meeting the duration limits in the NSR permit will ensure that the NH3 emission limits are not exceeded.	

Unit/Group/Process Information	
ID No.: WAP3A	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Fuel Type	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
Deviation Limit: If alternative fuel is fired for > 24 consecutive hours, report as a deviation, or conduct observation using Test Method 22. Report as a deviation if visible emissions are observed using Test Method 22 and opacity > 15% using Test Method 9.	
Basis of monitoring: Industry has demonstrated through performance tests and historical data that opacity and particulate matter standards are consistently met when combustion units fire natural gas only. If the emission unit fires a different fuel for more than 24 hours, the permit holder may elect to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: WAP3B	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Fuel Type	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
Deviation Limit: If alternative fuel is fired for > 24 consecutive hours, report as a deviation, or conduct observation using Test Method 22. Report as a deviation if visible emissions are observed using Test Method 22 and opacity > 15% using Test Method 9.	
Basis of monitoring: Industry has demonstrated through performance tests and historical data that opacity and particulate matter standards are consistently met when combustion units fire natural gas only. If the emission unit fires a different fuel for more than 24 hours, the permit holder may elect to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: WAP4	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Fuel Type	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
Deviation Limit: If alternative fuel is fired for > 24 consecutive hours, report as a deviation, or conduct observation using Test Method 22. Report as a deviation if visible emissions are observed using Test Method 22 and opacity > 15% using Test Method 9.	
Basis of monitoring: Industry has demonstrated through performance tests and historical data that opacity and particulate matter standards are consistently met when combustion units fire natural gas only. If the emission unit fires a different fuel for more than 24 hours, the permit holder may elect to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: WAPAB	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Fuel Type	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
Deviation Limit: If alternative fuel is fired for > 24 consecutive hours, report as a deviation, or conduct observation using Test Method 22. Report as a deviation if visible emissions are observed using Test Method 22 and opacity > 15% using Test Method 9.	
Basis of monitoring: Industry has demonstrated through performance tests and historical data that opacity and particulate matter standards are consistently met when combustion units fire natural gas only. If the emission unit fires a different fuel for more than 24 hours, the permit holder may elect to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: WAPACT5	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Visible emissions	
Minimum Frequency: Annually	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 15% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures. Historically, the cooling towers associated with the boilers at W. A. Parish Electric Generating Station have consistently been in compliance with the opacity standards under 30 TAC Chapter 111. Past observations have generally resulted in no visible emissions, with the exception of occasional water vapor. Therefore, it is expected that the likelihood of a violation of the 15% opacity standard for the cooling towers is extremely low. The emissions from these cooling towers, as well as the variability of emissions, are both extremely low; the cooling towers are only in operation while the combustion turbines are in operation. Furthermore, operation of the cooling towers is consistent across all turbine operation, regardless of the load. The only variability that exists would come from the ambient temperature, which may affect the presence of water vapor coming from the source.	

Unit/Group/Process Information	
ID No.: WAPACT6	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Visible emissions	
Minimum Frequency: Annually	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 15% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures. Historically, the cooling towers associated with the boilers at W. A. Parish Electric Generating Station have consistently been in compliance with the opacity standards under 30 TAC Chapter 111. Past observations have generally resulted in no visible emissions, with the exception of occasional water vapor. Therefore, it is expected that the likelihood of a violation of the 15% opacity standard for the cooling towers is extremely low. The emissions from these cooling towers, as well as the variability of emissions, are both extremely low; the cooling towers are only in operation while the combustion turbines are in operation. Furthermore, operation of the cooling towers is consistent across all turbine operation, regardless of the load. The only variability that exists would come from the ambient temperature, which may affect the presence of water vapor coming from the source.	

Unit/Group/Process Information	
ID No.: WAPACT7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Visible emissions	
Minimum Frequency: Annually	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 15% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures. Historically, the cooling towers associated with the boilers at W. A. Parish Electric Generating Station have consistently been in compliance with the opacity standards under 30 TAC Chapter 111. Past observations have generally resulted in no visible emissions, with the exception of occasional water vapor. Therefore, it is expected that the likelihood of a violation of the 15% opacity standard for the cooling towers is extremely low. The emissions from these cooling towers, as well as the variability of emissions, are both extremely low; the cooling towers are only in operation while the combustion turbines are in operation. Furthermore, operation of the cooling towers is consistent across all turbine operation, regardless of the load. The only variability that exists would come from the ambient temperature, which may affect the presence of water vapor coming from the source.	

Unit/Group/Process Information	
ID No.: WAPACT8	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Visible emissions	
Minimum Frequency: Annually	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 15% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures. Historically, the cooling towers associated with the boilers at W. A. Parish Electric Generating Station have consistently been in compliance with the opacity standards under 30 TAC Chapter 111. Past observations have generally resulted in no visible emissions, with the exception of occasional water vapor. Therefore, it is expected that the likelihood of a violation of the 15% opacity standard for the cooling towers is extremely low. The emissions from these cooling towers, as well as the variability of emissions, are both extremely low; the cooling towers are only in operation while the combustion turbines are in operation. Furthermore, operation of the cooling towers is consistent across all turbine operation, regardless of the load. The only variability that exists would come from the ambient temperature, which may affect the presence of water vapor coming from the source.	

Unit/Group/Process Information	
ID No.: WAPAUX1-4	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Visible emissions	
Minimum Frequency: Annually	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 15% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures. Historically, the cooling towers associated with the boilers at W. A. Parish Electric Generating Station have consistently been in compliance with the opacity standards under 30 TAC Chapter 111. Past observations have generally resulted in no visible emissions, with the exception of occasional water vapor. Therefore, it is expected that the likelihood of a violation of the 15% opacity standard for the cooling towers is extremely low. The emissions from these cooling towers, as well as the variability of emissions, are both extremely low; the cooling towers are only in operation while the combustion turbines are in operation. Furthermore, operation of the cooling towers is consistent across all turbine operation, regardless of the load. The only variability that exists would come from the ambient temperature, which may affect the presence of water vapor coming from the source.	

Unit/Group/Process Information	
ID No.: WAPGT1	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Fuel Type	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
Deviation Limit: If alternative fuel is fired for > 24 consecutive hours, report as a deviation, or conduct observation using Test Method 22. Report as a deviation if visible emissions are observed using Test Method 22 and opacity > 15% using Test Method 9.	
Basis of monitoring: Industry has demonstrated through performance tests and historical data that opacity and particulate matter standards are consistently met when combustion units fire natural gas only. If the emission unit fires a different fuel for more than 24 hours, the permit holder may elect to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: WAPMCT7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Visible emissions	
Minimum Frequency: Annually	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 15% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures. Historically, the cooling towers associated with the boilers at W. A. Parish Electric Generating Station have consistently been in compliance with the opacity standards under 30 TAC Chapter 111. Past observations have generally resulted in no visible emissions, with the exception of occasional water vapor. Therefore, it is expected that the likelihood of a violation of the 15% opacity standard for the cooling towers is extremely low. The emissions from these cooling towers, as well as the variability of emissions, are both extremely low; the cooling towers are only in operation while the combustion turbines are in operation. Furthermore, operation of the cooling towers is consistent across all turbine operation, regardless of the load. The only variability that exists would come from the ambient temperature, which may affect the presence of water vapor coming from the source.	

Unit/Group/Process Information	
ID No.: WAPMCT8	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-1
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Visible emissions	
Minimum Frequency: Annually	
Averaging Period: n/a	
Deviation Limit: It shall be considered a deviation if the opacity is greater than 15% averaged over a six-minute period.	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures. Historically, the cooling towers associated with the boilers at W. A. Parish Electric Generating Station have consistently been in compliance with the opacity standards under 30 TAC Chapter 111. Past observations have generally resulted in no visible emissions, with the exception of occasional water vapor. Therefore, it is expected that the likelihood of a violation of the 15% opacity standard for the cooling towers is extremely low. The emissions from these cooling towers, as well as the variability of emissions, are both extremely low; the cooling towers are only in operation while the combustion turbines are in operation. Furthermore, operation of the cooling towers is consistent across all turbine operation, regardless of the load. The only variability that exists would come from the ambient temperature, which may affect the presence of water vapor coming from the source.	

Obtaining Permit Documents

The New Source Review Authorization References table in the FOP specifies all NSR authorizations that apply at the permit area covered by the FOP. Individual NSR permitting files are located in the TCEQ Central File Room (TCEQ Main Campus located at 12100 Park 35 Circle, Austin, Texas, 78753, Building E, Room 103). They can also be obtained electronically from TCEQ's Central File Room Online (https://www.tceq.texas.gov/goto/cfr-online). Guidance documents that describe how to search electronic records, including Permits by Rule (PBRs) or NSR permits incorporated by reference into an FOP, archived in the Central File Room server are available at https://www.tceq.texas.gov/permitting/air/nav/air_status_permits.html

All current PBRs are contained in Chapter 106 and can be viewed at the following website:

https://www.tceq.texas.gov/permitting/air/permitbyrule/air_pbr_index.html

Previous versions of 30 TAC Chapter 106 PBRs may be viewed at the following website:

www.tceq.texas.gov/permitting/air/permitbyrule/historical_rules/old106list/index106.html

Historical Standard Exemption lists may be viewed at the following website:

www.tceq.texas.gov/permitting/air/permitbyrule/historical_rules/oldselist/se_index.html

Additional information concerning PBRs is available on the TCEQ website:

https://www.tceq.texas.gov/permitting/air/nav/air_pbr.html

Compliance Review

1. In accordance with 30 TAC Chapter 60, the compliance history was reviewed on **May 9, 2024.**
   Site rating: 1.21 / Satisfactory   Company rating: 0.24 / Satisfactory
   (High < 0.10; Satisfactory ≥ 0.10 and ≤ 55; Unsatisfactory > 55)
2. Has the permit changed on the basis of the compliance history or site/company rating?...No

Site/Permit Area Compliance Status Review

1. Were there any out-of-compliance units listed on Form OP-ACPS?...No
2. Is a compliance plan and schedule included in the permit? ....No

Available Unit Attribute Forms

OP-UA1 - Miscellaneous and Generic Unit Attributes
OP-UA2 - Stationary Reciprocating Internal Combustion Engine Attributes
OP-UA3 - Storage Tank/Vessel Attributes
OP-UA4 - Loading/Unloading Operations Attributes
OP-UA5 - Process Heater/Furnace Attributes
OP-UA6 - Boiler/Steam Generator/Steam Generating Unit Attributes
OP-UA7 - Flare Attributes
OP-UA10 - Gas Sweetening/Sulfur Recovery Unit Attributes
OP-UA11 - Stationary Turbine Attributes
OP-UA12 - Fugitive Emission Unit Attributes
OP-UA13 - Industrial Process Cooling Tower Attributes
OP-UA14 - Water Separator Attributes
OP-UA15 - Emission Point/Stationary Vent/Distillation Operation/Process Vent Attributes
OP-UA16 - Solvent Degreasing Machine Attributes
OP-UA17 - Distillation Unit Attributes
OP-UA18 - Surface Coating Operations Attributes
OP-UA19 - Wastewater Unit Attributes
OP-UA20 - Asphalt Operations Attributes
OP-UA21 - Grain Elevator Attributes
OP-UA22 - Printing Attributes
OP-UA24 - Wool Fiberglass Insulation Manufacturing Plant Attributes

OP-UA25 - Synthetic Fiber Production Attributes
OP-UA26 - Electroplating and Anodizing Unit Attributes
OP-UA27 - Nitric Acid Manufacturing Attributes
OP-UA28 - Polymer Manufacturing Attributes
OP-UA29 - Glass Manufacturing Unit Attributes
OP-UA30 - Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mill Attributes
OP-UA31 - Lead Smelting Attributes
OP-UA32 - Copper and Zinc Smelting/Brass and Bronze Production Attributes
OP-UA33 - Mineral Processing Plant Attributes
OP-UA34 - Pharmaceutical Manufacturing
OP-UA35 - Incinerator Attributes
OP-UA36 - Steel Plant Unit Attributes
OP-UA37 - Basic Oxygen Process Furnace Unit Attributes
OP-UA38 - Lead-Acid Battery Manufacturing Plant Attributes
OP-UA39 - Sterilization Source Attributes
OP-UA40 - Ferroalloy Production Facility Attributes
OP-UA41 - Dry Cleaning Facility Attributes
OP-UA42 - Phosphate Fertilizer Manufacturing Attributes
OP-UA43 - Sulfuric Acid Production Attributes
OP-UA44 - Municipal Solid Waste Landfill/Waste Disposal Site Attributes
OP-UA45 - Surface Impoundment Attributes
OP-UA46 - Epoxy Resins and Non-Nylon Polyamides Production Attributes
OP-UA47 - Ship Building and Ship Repair Unit Attributes
OP-UA48 - Air Oxidation Unit Process Attributes
OP-UA49 - Vacuum-Producing System Attributes
OP-UA50 - Fluid Catalytic Cracking Unit Catalyst Regenerator/Fuel Gas Combustion Device/Claus Sulfur Recovery Plant Attributes
OP-UA51 - Dryer/Kiln/Oven Attributes
OP-UA52 - Closed Vent Systems and Control Devices
OP-UA53 - Beryllium Processing Attributes
OP-UA54 - Mercury Chlor-Alkali Cell Attributes
OP-UA55 - Transfer System Attributes
OP-UA56 - Vinyl Chloride Process Attributes
OP-UA57 - Cleaning/Depainting Operation Attributes
OP-UA58 - Treatment Process Attributes
OP-UA59 - Coke By-Product Recovery Plant Attributes
OP-UA60 - Chemical Manufacturing Process Unit Attributes
OP-UA61 - Pulp, Paper, or Paperboard Producing Process Attributes
OP-UA62 - Glycol Dehydration Unit Attributes
OP-UA63 - Vegetable Oil Production Attributes
OP-UA64 - Coal Preparation Plant Attributes