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Amended Air Quality Standard Permit for Electric Generating Units

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SUMMARY DOCUMENT FOR AMENDED AIR QUALITY STANDARD PERMIT FOR ELECTRIC GENERATING UNITS

I. EXECUTIVE SUMMARY

In accordance with Title 30 Texas Administrative Code (30 TAC) § 116.605, Standard Permit Amendment and Revocation, the Texas Commission on Environmental Quality (TCEQ or commission) is issuing amendments to the air quality standard permit for electric generating units (EGUs). The amendments increase the nitrogen oxides (NO_x) emission limit for EGUs with a capacity of 250 kilowatts (kW) or less, located in East Texas and operated for more than 300 hours per year. The amendments would also increase the NO_x emission limit for EGUs that combust landfill gas, digester gas, or stranded oilfield gas. The amendments would provide a more flexible NO_x emission limit during periods of reduced load, and periods of extremely low ambient temperatures. The amendments provide more flexibility concerning the use of renewable fuels, and would eliminate the hydrogen sulfide (H_2S) concentration limit for gaseous fuels. The amendments also would exclude boilers from using the EGU standard permit, as the recently-issued boiler standard permit is more appropriate for that type of combustion equipment. Other amendments improve the organization, readability, and enforceability of the standard permit.

II. EXPLANATION AND BACKGROUND OF AIR QUALITY STANDARD PERMIT

The New Source Review (NSR) Program under 30 TAC Chapter 116, Control of Air Pollution by Permits for New Construction or Modification, requires any person who plans to construct any new facility or to engage in the modification of any existing facility which may emit air contaminants into the air of the state to obtain a permit pursuant to 30 TAC § 116.111, General Application, or satisfy the conditions of a standard permit, a flexible permit, a permit by rule, or the criteria for a de minimis facility or source before any actual work begins on the facility. A standard permit authorizes the construction or modification of new or existing facilities which are similar in terms of operations, processes, and emissions. A standard permit provides an efficient mechanism for qualifying facilities to obtain authorization as an alternative to a case-specific air quality permit.

The standard permit for electric generating units first became effective on June 1, 2001, and has not been amended previously. The standard permit is applicable to units such as engines, turbines, fuel cells, or other devices used to generate electricity for use by the owner or operator, and/or generate electricity to be sold to the electric grid. These EGUs are typically sited at or near a load that will consume most of the electricity generated. The standard permit was designed to provide a streamlined permitting method to encourage the use of clean electric generating technologies. However, the standard permit is not intended to provide an authorization mechanism for all possible unit configurations or for unusual operating scenarios. Those facilities which cannot meet the standard permit conditions may apply for a case-by-case review of an air quality permit under 30 TAC § 116.111.

III. OVERVIEW OF AIR QUALITY STANDARD PERMIT AMENDMENTS

The commission is amending the NO_x limits that apply to small EGUs in East Texas. Under the previous standard permit, all units constructed on or after January 1, 2005 in East Texas which operate more than 300 hours per year were required to meet a NO_x standard of 0.14 pounds per megawatt-hour (lb/MWh), regardless of size. The amended standard permit allows EGUs with a capacity of 250 kW or less to comply with a limit of 0.47 lb/MWh, which was the standard in effect prior to January 1, 2005. The commission is adopting this change because the technology needed for very small EGUs to comply with a standard of 0.14 lb/MWh has not developed as rapidly as the commission anticipated. Most small engines, turbines, and microturbines are not currently able to meet the 0.14 lb/MWh standard without additional emission control (such as selective catalytic reduction). While such additional control is reasonable on larger units, it may not be practical for very small units. This change will make it easier to authorize small engines and turbines that have minimal NO_x emissions, while maintaining appropriate control over NO_x sources in East Texas.

The commission is also amending the NO_x emission limit for EGUs combusting landfill gas, digester gas, and oilfield gases. The previous NO_x emission limit for units combusting landfill gas, digester gas, and oilfield gas was 1.77 lb/MWh. The amended NO_x emission limit for these units is 1.90 lb/MWh. The commission is adopting this change because the previous limit of 1.77 lb/MWh did not sufficiently account for generator losses, and may have restricted operational capacity and flexibility by requiring operators to de-rate engines in order to achieve the standard. In addition, the commission seeks to encourage the use of these waste gases to produce energy, as opposed to direct flaring or other combustion which would not produce a useful benefit, and it appears that the previous standard of 1.77 lb/MWh may have limited the beneficial use of these waste fuel sources.

The commission also adopts an amendment to expand the allowed fuel types under the standard permit, to include gaseous and liquid renewable fuels. The previous standard permit did not allow use of gaseous renewable fuels other than landfill gas and digester gas. The previous standard permit allowed the use of liquid renewable fuels, but the commission believes additional clarification concerning the use of liquid renewable fuels would be beneficial. The amendments would require gaseous and liquid renewable fuels to comply with a NO_x standard of 1.90 lb/MWh, which is the revised standard previously associated with the use of landfill gas, digester gas, and oilfield gas. In order to be eligible to use the more flexible 1.90 lb/MWh standard, gaseous and liquid fuels must contain at least 75% landfill gas, digester gas, stranded oilfield gas, or renewable fuel content by volume.

The commission also adopts an amendment to eliminate the H_2S fuel concentration limit for landfill gas, digester gas, and stranded oilfield gas, because the standard permit contains a total sulfur fuel concentration limit which is sufficiently protective of human health and the environment.

The commission also adopts several amendments to improve the organization, readability, and enforceability of the standard permit.

IV. PERMIT CONDITION ANALYSIS AND JUSTIFICATION

The commission adopts minor grammatical amendments to the introductory paragraph to comply with current style requirements.

The commission adopts new subsection (1)(B), which prohibits the use of the EGU standard permit to authorize boilers. The EGU standard permit was primarily intended to authorize turbines, engines, and fuel cells. No boilers have been authorized by the EGU standard permit to date. The commission recently issued an Air Quality Standard Permit for Boilers which contains technical requirements that are appropriate for boilers, and it would be administratively inefficient to authorize boilers under both the EGU standard permit and the Boiler standard permit.

The commission adopts a definition for renewable fuel under new subsection (2)(D). A definition of this term is necessary because gaseous and liquid renewable fuels are allowed fuel types under the revised standard permit.

The commission adopts a minor grammatical amendment to subsection (3)(A), substituting the word "that" for the word "which."

The commission adopts an amendment to subsection (3)(B) to expand the abbreviations "MW" and "NO_x" to megawatt and nitrogen oxides, respectively.

The commission adopts an amendment to subsection (3)(D) to replace the outdated reference to the Texas Natural Resource Conservation Commission (TNRCC) with a reference to the Texas Commission on Environmental Quality (TCEQ). The commission adopts amendments to paragraphs (3)(D)(ii)-(iii) to clarify and enhance the recordkeeping associated with recertifications under subsection (4)(G), and to add a new recordkeeping requirement to document compliance with the fuel sulfur content limits of the standard permit. The recordkeeping under new paragraph (3)(D)(iii) is necessary to ensure that the commission has adequate means to verify compliance with the fuel sulfur content limits.

The commission adopts an amendment to subsection (3)(E) to include a reference to Title 40 Code of Federal Regulations Part 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, which applies to turbines that are constructed, modified, or reconstructed after February 18, 2005. This new federal performance standard may affect some units authorized under the standard permit and the amendment is intended to ensure that owners and operators are aware of these regulations and comply with any applicable requirements.

The commission adopts an amendment to subsection (3)(F) to include a reference to 30 TAC Chapter 114, Control of Air Pollution from Motor Vehicles, because Chapter 114 contains rules which may affect fuels used by some units authorized by this standard permit. Specifically, Subchapter H of Chapter 114 contains requirements for low emission gasoline and diesel fuels.

The commission adopts amendments to subsection (4)(A). The amendments specify that alternative test methods may be used for certification, with approval by the executive director. Another amendment to this subsection specifies that the unit must be operated using the same fuel(s) for which it was certified. This amendment is necessary to ensure that the unit is operated in a manner consistent with the conditions under which the unit was certified. Note that all fuels that will be used by the EGU must be addressed in the registration required by subsection (3)(A). The commission also adopts minor grammatical amendments to this subsection to improve readability and correct outdated references.

The commission adopts an amendment to subsection (4)(B), to replace the reference to "paragraphs" with the more general reference to subsections. In addition, the commission has renumbered existing subsections (4)(C), (4)(D), and (4)(E) as subsections (4)(D), (4)(E), and (4)(F) respectively, to account for organizational changes within the amended standard permit.

The commission adopts new subsection (4)(C). The amendments consolidate fuel type requirements and fuel sulfur limitations within subsection (4)(C). Previous subsection (4)(C) has been renumbered as subsection (4)(D), and subsequent previous subsections (4)(D)-(4)(F) are similarly renumbered as (4)(E)-(4)(G) respectively. The amended subsection (4)(C) is intended to provide greater clarity regarding allowable fuel types and sulfur restrictions. Adopted subsection (4)(C) does not include the H_2S fuel concentration limit currently located in existing subsection (4)(E). The H_2S fuel concentration limit is redundant because the total sulfur concentration limit is protective of human health and the environment. The content of adopted subsection (4)(C) is a rearrangement and clarification of existing requirements and does not impose any new obligations.

The commission adopts amendments to previous subsection (4)(C), which has been renumbered as subsection (4)(D). The adopted subsection contains emission limits for EGUs having a capacity of 10 MW or less. The amendments revise the NO_x emission limit for units in East Texas with a capacity of less than or equal to 250 kW. These very small units are now required to comply with an emission standard of 0.47 lb/MWh, which was the standard that was in effect prior to January 1, 2005. The previous standard (for all units constructed on or after January 1, 2005) was 0.14 lb/MWh. This increase in the NO_x standard for very small units is necessary because at the present time there do not appear to be any widely used, practical technologies to enable units in this capacity range to meet the 0.14 lb/MWh standard. The commission had proposed to increase the NO_x emission standard for units with a capacity of 100 kW or less, but the commission has increased the capacity threshold to 250 kW for the adopted standard permit. This change from the proposed level of 100 kW is partially in response to comments requesting a higher capacity threshold, although commenters generally requested an even higher capacity threshold than 250 kW. The adopted 250 kW capacity threshold is intended to provide additional relief for small engines and turbines that have minimal NO_x emissions, and would be impractical to control to a level of 0.14 lb/MWh. The commission has maintained the 0.14 lb/MWh NO_x limit for units exceeding 250 kW to minimize the NO_x impact on East Texas and to avoid undermining existing and developing NO_x control technologies for larger units. The commission selected a 250 kW transition point because there are commercially available EGUs in this size range that can meet the 0.14 lb/MWh limit. In addition, a review of commission records indicates that there was minimal deployment of units between 250 kW and 1 MW when the 0.47 lb/MWh standard applied, suggesting that there would be little benefit in selecting a higher capacity threshold for the 0.47 lb/MWh emission limit. The amended subsection (4)(D) also states that an EGU certified to meet federal non-road engine standards (under Title 40 Code of Federal Regulations [CFR] Part 89) is automatically deemed to satisfy the 21 lb/MWh West Texas standard. Although the 21 lb/MWh limit in the standard permit was based on the federal standards, some engines which are certified under the federal standards may not achieve 21 lb/MWh under all operating conditions. It was always TCEQ's intent that engines certified under 40 CFR Part 89 would qualify for the West Texas standard for units operating 300 hours or less, and this change is necessary to ensure that federally certified engines are eligible to use the standard permit. This change will reduce the need for additional testing when engines have already been tested and certified under 40 CFR Part 89.

The commission adopts amendments to previous subsection (4)(D), which is also renumbered as subsection (4)(E). The amendments delete unnecessary language to improve readability, update references, and include minor grammatical changes to maintain consistency with current style requirements.

The commission adopts amendments to previous subsection (4)(E), which is also renumbered as subsection (4)(F). This subsection previously specified emission limits for units which burn landfill gas, oilfield gas, and digester gas in East Texas. The amendments add the term "stranded" to clarify the type of oilfield gas which is subject to the emission standard contained in this subsection. The amendments increase the applicable NO_x limit for these fuel types from 1.77 lb/MWh to 1.90 lb/MWh. This increase is necessary because the current limit does not account for all mechanical generator losses and may require the operator to de-rate engines in order to meet the standard. The amendments also add gaseous and liquid renewable fuels under this subsection. Although liquid renewable fuels were not proposed to be covered under this subsection, the commission has added liquid renewable fuels to this subsection in response to comments that suggested that all renewable fuels should be treated equally, under the same emission standard. Therefore, the commission has added liquid renewable fuels to the classes of fuels which qualify for the 1.90 lb/MWh emission standard. However, as a practical matter it may be difficult for liquid fuels to meet the 1.90 lb/MWh standard, so the commission does not anticipate high-volume use of liquid renewable fuel under the 1.90 lb/MWh standard. In order to qualify for the 1.90 lb/MWh emission standard, fuels must contain at least 75% landfill gas, digester gas, stranded oilfield gas, or renewable fuel content by volume. The minimum concentration of 75% is necessary to ensure that projects which qualify for the 1.90 lb/MWh emission standard are using the waste gas or renewable fuel as the primary fuel source, and are not circumventing the normal emission limit by using only a small amount of waste gas or renewable fuel in combination with fossil fuels. The amendments also clarify the applicability of this subsection to units in West Texas. Units that burn landfill gas, stranded oilfield gas, digester gases, or any gaseous or liquid renewable fuel in West Texas and have a capacity greater than 10 MW are subject to the 1.90 lb/MWh NO_x emission limit in adopted subsection (4)(F). Units that burn landfill gas, stranded oilfield gas, digester gases, or any gaseous or liquid renewable fuel in

West Texas and have a capacity of 10 MW or less would be allowed to comply with the applicable West Texas emission limit in adopted subsection (4)(D), which is less stringent than the 1.90 lb/MWh emission limit in adopted subsection (4)(F).

The commission adopts amendments to previous subsection (4)(F), which is also renumbered as subsection (4)(G). The amendments allow use of California Air Resources Board test methods, or alternative test methods approved by the executive director, to improve flexibility for recertification of units. The adopted recertification requirements in subsection (4)(G) are consistent with the revised certification requirements in subsection (4)(A). The amendments include a requirement that recertified units must operate using the same fuel(s) for which they were recertified, to ensure that the unit is operated in a manner consistent with the conditions under which the unit was recertified.

The content of previous subsection (4)(G) has been relocated to subsection (4)(C).

The commission adopts new subsection (4)(H). This subsection is in response to comments concerning the applicability of the NO_x limits at extremely low ambient temperatures, and comments about the applicability of the NO_x limits during periods when an EGU is operating at reduced load. EGUs operating at reduced load, or in extremely low ambient temperatures, may have difficulty meeting the NO_x emission standards. The commission has added a provision under new subsection (4)(H) to specify that units operating at less than 80% load may comply with an alternative emission limit. The alternative emission limit is an hourly NO_x emission rate that equals the NO_x emission rate (lb/hr) that the unit would emit at full load. To determine the alternative emission limit, multiply the unit's rated capacity (in MW) by the applicable emission limit in subsections (4)(D)-(4)(F). Owners or operators seeking to claim the alternative emission limit must maintain records to demonstrate that the unit complies with the alternative emission limit. The commission has also added a provision under new subsection (4)(H) to specify that the NO_x emission limits do not apply when ambient temperatures at the location of the EGU are below zero degrees Fahrenheit. This exemption from the NO_x limits will not have a significant effect on ozone formation, which is not normally a concern under very cold weather conditions. In addition, subzero weather in Texas typically occurs in attainment areas where NO_x is a less critical concern.

V. PROTECTIVENESS REVIEW

The primary pollutant of concern emitted from EGUs is NO_x. Other emissions from EGUs include particulate matter, sulfur compounds, carbon monoxide, and volatile organic compounds (VOC). The characteristics of the emissions vary depending on the type of technology employed, the type of fuel used, and the type of emission control techniques applied to the source.

The amendments allow very small units in East Texas (those having a capacity less than or equal to 250 kW) to comply with the pre-2005 limit of 0.47 lb NO_x/MWh, instead of meeting the 0.14 lb/MWh limit which the standard permit currently requires. The original protectiveness review was based on a 0.47 lb/MWh limit for units 10 MW or less, so restoring the 0.47 lb/MW limit for very small units is still protective. At a capacity of 250 kW, the emission rate authorized under the proposed standard of 0.47 lb/MWh would be very small. Additionally, state and federal permits for combustion units at power plants ranging from 50 to 2000 MW have been reviewed and modeling has shown that even much larger units meet all National Ambient Air Quality Standards (NAAQS) and state standards.

The amendments to the NO_x limit for units combusting landfill gas, stranded oilfield gas, digester gas, and other gaseous and liquid renewable fuels would increase allowable NO_x emissions from 1.77 lb/MWh to 1.90 lb/MWh. The proposed standard of 1.90 lb/MWh is considerably more stringent than the emission limitations in permit by rule 30 TAC § 106.512, Stationary Engines and Turbines, which the commission has previously determined to be protective. Additionally, state and federal permits for combustion units at landfills that were too large to use this standard permit have been reviewed and modeling has shown that even these much larger units meet all NAAQS and state standards.

The amendments eliminate the hydrogen sulfide (H_2S) concentration limit for landfill gas, digester gas, and stranded oilfield gas used as fuel. When a fuel containing sulfur compounds is combusted in a unit such as an engine or turbine, the various sulfur compounds in the fuel are converted to the same oxidized sulfur products, regardless of whether the fuel contained H_2S or other reduced sulfur compounds. The deletion of the H_2S concentration limit will not affect the protectiveness of the standard permit because the total fuel sulfur limit would remain in place, and is protective.

VI. PUBLIC NOTICE AND COMMENT PERIOD

In accordance with 30 TAC § 116.605, Standard Permit Amendment and Revocation, the TCEQ published notice of the proposed amendments to this standard permit in the *Texas Register* and newspapers of the largest general circulation in Austin, Houston and Dallas. The date for these publications was April 7, 2006. The public comment period closed on May 10, 2006.

VII. PUBLIC MEETING

A public meeting on the proposal was held on May 10, 2006, at the Texas Commission on Environmental Quality, 12100 Park 35 Circle, Austin, Texas.

VIII. ANALYSIS OF COMMENTS

Written comments were received from Central Pallet, Inc., Corrugated Services, L.P., Cratech, Inc., the Engine Manufacturers Association (EMA), Good Company Associates (on behalf of the Texas Distributed Generation Working Group), Greatwide Distribution Logistics, GWG Wood Group, HCS Group, Inc., Letco Group L.P., Lloyd Gosselink on behalf of Safe Fuels, Inc. (Lloyd Gosselink), Service Waste Inc., Solar Turbines, Inc., Sunergie, Inc., Texas Renewable Energy Industries Association (TREIA), United States Department of Energy (US DoE), White's Wood Group, Inc., and Zilkha Biomass Energy, L.L.C. (Zilkha). Oral comments were received from Good Company Associates, representing the Texas Distributed Generation Working Group. The commenters generally suggested changes to the proposed amendments to the standard permit.

Cratech Inc. indicated support for the proposed amendments, specifically concerning the use of gaseous fuels derived from biomass.

The commission appreciates the support.

Lloyd Gosselink and TREIA generally supported the proposed inclusion of biodiesel as an accepted type of renewable fuel under the standard permit.

The commission appreciates the support.

Lloyd Gosselink and TREIA commented that under the proposed standard permit, liquid renewable fuels such as biodiesel are treated in the same manner as conventional, non-renewable liquid fuels, while gaseous renewable fuels would be allowed to meet a proposed emission limit of 1.90 lb/MWh. Lloyd Gosselink and TREIA commented that all renewable fuels should be treated similarly, regardless of whether they are liquid renewable fuels or gaseous renewable fuels. Lloyd Gosselink and TREIA commented that the use of all forms of renewable fuel should be encouraged.

The commission concurs that, considering the direct and indirect benefits of renewable fuels, it is appropriate that liquid renewable fuels be categorized with gaseous renewable fuels under the proposed 1.90 lb/MWh standard. The commission has modified the standard permit conditions accordingly. However, in practice, it may be difficult for liquid renewable fuels to achieve the 1.90 lb/MWh standard without a high degree of emission control. Liquid renewable fuels may be more practical to employ in West Texas areas, which are subject to less stringent NO_x limitations. Although the commission desires to encourage the use of renewable fuels, the commission must carefully consider the environmental impacts of each authorized fuel type, particularly in areas such as East Texas, which are highly sensitive to NO_x emissions and corresponding ozone nonattainment concerns.

Zilkha, Sunergie Inc., and TREIA commented that the standard permit should allow use of renewable solid fuels (such as biomass). Zilkha stated that, as proposed, the standard permit was biased towards renewable generation powered by liquid and gaseous fuels. Zilkha and Sunergie Inc. suggested that emissions from solid renewable fuels could be minimized by only allowing those renewable fuels that contain no foreign additives not found in the fuel's natural state.

The commission has considered the possible inclusion of solid renewable fuels as an allowed fuel type under the standard permit. The varied composition of solid renewable fuels and the technical complexity associated with the handling and combustion of those fuels makes it difficult to address such a broad category in a standard permit. For example, various types of solid fuels may have widely varying concentrations of sulfur, chlorine, nitrogen, mercury, or other constituents, that could result in unacceptable emissions of these compounds. In addition, combustion of some solid fuels may result in excessive particulate

matter emissions or excessive organic hazardous air pollutant (HAP) emissions. The use of solid fuels also produces emissions from material handling that may be significant. These factors make a case-by-case, detailed review necessary to ensure protection of human health and the environment. For this reason, it is not suitable to authorize combustion of all solid renewable fuels in the standard permit. In addition, solid fuels tend to be used to fire boilers, rather than units such as engines or turbines, and the commission has determined that boilers should be authorized under the recently-issued Air Quality Standard Permit for Boilers (Boiler standard permit), not the Air Quality Standard Permit for Electric Generating Units (EGU standard permit). No changes were made in response to this comment.

HCS Group, Inc., Central Pallet, Inc., Corrugated Services, L.P., Service Waste, Inc., White's Wood Group, Letco Group, L.P., Greatwide Distribution Logistics, and GWG Wood Group commented that wood should be an allowed fuel type under the standard permit. HCS Group, Inc. commented that the overall societal benefits of wood as a fuel make it a more attractive fuel than natural gas. Some examples of the societal benefits that HCS Group, Inc. cited includes: reduced consumption of fossil fuels, no net increase of carbon content above ground, reduced landfill burdens, and reduced transportation impacts associated with disposal of wood waste. Central Pallet, Inc. commented that wood-fueled power projects would increase energy independence and improve energy supply reliability and efficiency. GWG Wood Group commented that use of wood would reduce consumption of fossil fuels. Central Pallet, Inc., GWG Wood Group, and White's Wood Group commented that small CHP plants using wood as fuel could deliver greater energy efficiency than larger biomass to energy plants. Corrugated Services, L.P., Service Waste, Inc., Letco Group, L.P., and Greatwide Distribution Logistics commented that allowing wood as a fuel type would reduce the volume of wood waste directed to landfills. Central Pallet, Inc., and Service Waste, Inc. recommended an emission limit of 0.55 lb NO_x/MWh for wood fired units. HCS Group, Inc. and Corrugated Services, LP recommended an emission limit of 1.90 lb NO_x/MWh for wood fired units. HCS Group, Inc. suggested an emission limit of 0.55 lb NO_x/MWh as an alternative if the 1.90 lb/MWh limit was not feasible. HCS Group, Inc. commented that other pollutants (such as particulate matter, HAPs, and others) could be accounted for and addressed through the PI-1S registration process.

Although waste wood does appear to be a promising fuel source with considerable benefits, after careful consideration the commission has determined that it would not be appropriate to authorize wood-fired EGUs under this standard permit. This is due to a combination of technical and strategic factors. The EGU standard permit was primarily intended to authorize units such as turbines, engines, and fuel cells. By their nature, these units cannot typically operate on solid fuels, and solid fuels were never contemplated during the development of the original EGU standard permit. The commission does not have a large body of information about the range of emissions from wood-fired units and associated material handling and fugitive sources. Due to this current lack of information, an attempt to authorize wood-fired units in a standard permit at this time would require a number of stringent conditions and restrictions that would result in a very limited authorization which would most likely serve little practical use. At the present time, a case-by-case NSR

permit is the best means to ensure protection of human health, while simultaneously allowing adequate operational flexibility for wood-fired units.

In addition, the commission has recently issued a standard permit for boilers, and even if the technical and environmental factors associated with wood-fired boilers can be resolved such that authorization under a standard permit would be feasible, it would be more appropriate for those units to be addressed under the Boiler standard permit than the EGU standard permit. The boiler standard permit was developed specifically to address boilers, and includes emission standards and monitoring requirements that are specifically intended for boilers. It would be inappropriate for the EGU standard permit to overlap with the boiler standard permit. For these reasons, the commission has added a restriction to exclude boilers from claiming the EGU standard permit as a method of authorization. Boilers will need to be authorized under the boiler permit by rule in 30 TAC § 106.183 Boilers, Heaters, and Other Combustion Devices, the boiler standard permit, or a case-by-case NSR permit.

US DoE commented that the proposed standard permit did not allow for the use of a comprehensive mix of biomass fuels. US DoE commented that allowing a broader range of biomass fuels would provide more flexibility for electrical production, and co-feeding of biomass and biomass-derived synthesis gas with fossil fuels would reduce NO_x, SO_x, and H_2S emissions. US DoE recommended that the definition of renewable fuels be revised to include woody biomass; forest, yard, or agricultural crop residues; grasses; biomass synthesis gas; and black liquor from pulp mills.

The commission encourages the use of renewable fuels, including fuels derived from biomass. The standard permit would allow the use of gaseous fuels derived from biomass. However, the use of fuels such as grasses, crop residues, or black liquor poses a more complex situation that makes a case-by-case review of those fuels necessary to ensure protection of human health and the environment. Therefore, the commission declines to incorporate those fuels into the standard permit.

EMA indicated general support for amending the NO_x emission limits for small EGUs in East Texas. However, EMA commented that the proposed changes are too narrow in scope, and did not sufficiently address larger units (units having a capacity greater than 100 kW but equal to or less than 2 MW). EMA commented that even at a NO_x emission limit of 0.5 lb/MWh, a 100 percent compliance rate for engines is not feasible due to variations in fuel composition, operating conditions, and ambient environmental factors. EMA also commented that the cost of emission reduction systems that could meet those levels is not economically feasible. EMA recommended a NO_x standard for distributed generation (DG) sources in East Texas in the range of 1.4 - 2.2 lbs/MWh, for units with a capacity of 2 MW or less. EMA commented that these higher emission limits would allow wider use of high efficiency engines with CHP, which EMA stated are more efficient power producers than central station power plants, microturbines, or fuel cells.

The commission acknowledges that the proposed changes were limited. NO_x emissions in East Texas are a major concern, and the standard permit is intended to ensure that DG projects in East Texas do not interfere with attainment of the ozone standard. The commission does not support EMA's proposed NO_x standard of 1.4 - 2.2 lb/MWh, for units with a capacity of 2 MW or less. A number of existing technologies are able to achieve significantly better NO_x performance than EMA's suggested limit, at reasonable cost. However, the commission has increased the capacity threshold for the 0.14 lb/MWh standard to 250 kW instead of the proposed 100 kW. This change will make it easier to authorize small engines and turbines that have minimal NO_x emissions, while maintaining appropriate control over NO_x sources in East Texas. The commission selected a 250 kW transition point because there are commercially available EGUs in this size range that can meet the 0.14 lb/MWh limit; a review of commission records indicates that there was minimal deployment of units between 250 kW - 1 MW even when the 0.47 lb/MWh standard applied; and units smaller than 250 kW are very small sources of NO_x even when operating under a 0.47 lb/MWh limit.

Zilkha, Sunergie, Inc., and TREIA commented that the proposed increase in the allowed East Texas NO_x limit for very small units (those equal to or less than 100 kW) does not sufficiently address the difficulty of controlling small units. Zilkha and Sunergie, Inc. recommended a de minimis threshold of 35 tons per year, to allow small units with relatively insignificant annual emissions to qualify for the standard permit. Zilkha and Sunergie, Inc. also recommended that the capacity level for the proposed 0.47 lb/MWh standard be increased from 100 kW to 5 MW.

The commission does not agree that the standard permit should employ a de minimis NO_x threshold of 35 tons per year. The cumulative effect of a number of 35 tpy units could be significant. The commission also does not agree that the capacity level for the 0.47 lb/MWh standard should be raised to 5 MW, because this could also result in significant NO_x emissions. However, the commission has revised the standard permit to allow units up to 250 kW to comply with the 0.47 lb/MWh emission limit.

Good Company Associates (on behalf of the Texas Distributed Generation Working Group) commented that technology in the distributed generation industry has not progressed according to the 2001 forecasts that the East Texas 0.14 lb/MWh standard was based upon. Good Company Associates commented that the proposed changes are not sufficient to address the needs of the distributed generation industry.

The commission acknowledges that distributed generation technology has not progressed to the extent expected when the 0.14 lb/MWh standard was established. However, technology is available that can meet the terms and conditions of the EGU standard permit, at reasonable cost. The increased capacity threshold (250 kW) associated with the 0.14 lb/MWh standard will make it easier for small engines and turbines to be authorized under the standard permit. The increased NO_x limit for units firing landfill gas, digester gas, and stranded oilfield gas, will make the standard permit more functional for those units. The adopted standard permit also provides increased flexibility for units operating on

renewable fuels, and more flexibility for situations involving reduced loads and cold ambient temperatures. However, the EGU standard permit is not intended to cover every project, and applicants maintain the option to obtain authorization under a case-by-case permit in cases where the EGU standard permit is not suitable.

Good Company Associates commented that there are no mature technologies that can meet and sustain the 0.14 lb/MWh NO_x emission limit without the use of additional control technologies (such as the combined use of exhaust gas recirculation and selective catalytic reduction [SCR]). Good Company Associates commented that application of SCR typically costs between $25,000 and $40,000 per ton of NO_x controlled, which is several times the $5,500 per ton that TCEQ pays for NO_x reductions under the TERP program. Good Company Associates also commented that the capital costs for continuous monitoring equipment for these size projects ranges between $150,000 and $200,000, and does not include expensive annual operating and maintenance costs.

The commission does not agree that there are no technologies that can meet and sustain the 0.14 lb/MWh emission limit. Equipment such as the Solar Mercury turbine, the Lean One engine from Blue Point Energy, engine control packages from Attainment Technologies Inc., and catalytic turbine technology from Catalytica, Inc., have the potential to meet the emission standard. In some cases, additional control or CHP credit may be needed in addition to the base unit. Additional low-NO_x technologies are being developed by several vendors. The costs associated with the operation and maintenance of the various controls will vary greatly depending on the individual project. In cases where meeting the standard permit is not economically feasible, applicants may apply for a case-by-case NSR permit, where specific costs can be further considered in the Best Available Control Technology (BACT) determination. No changes were made in response to this comment.

Good Company Associates commented that, based on a review of certified emission results for nearly 200 internal combustion engines in California's SCAQMD, the only systems found to meet the 0.14 lb/MWh limit without aftertreatment were 4 natural gas engines with a capacity of 100 kW or less. Of units between 100 kW and 10 MW, only one engine was close to meeting the 0.14 lb/MWh standard. The average emission performance for the other units was over 13.42 lb/MWh.

The commission anticipates that a majority of in-service engines would have NO_x emissions exceeding the East Texas 0.14 lb/MWh standard. The EGU standard permit does not specify the type of equipment that must be used (engine, turbine, fuel cell, etc.) so in cases where an engine is unable to meet the terms of the standard permit, the registrant could consider other equipment types, or consider applying for a case-by-case permit. No changes were made in response to this comment.

Good Company Associates commented that the February 2005 EPA standard for new stationary combustion turbines with a capacity under 30 MW is 1.0 lb NO_x/MWh. Good Company Associates commented that EPA considered the use of SCR in setting the NO_x standard, but EPA determined that the costs for SCR were high compared to the incremental difference in emissions. Good Company Associates also noted that EPA determined that SCR and other control measures could be infeasible on small turbines because of space considerations and the small size of the turbine combustion chamber. Good Company Associates commented that the only turbine that can approach the 0.14 lb/MWh standard is the Solar Mercury 50, which is capable of NO_x emissions as low as 0.17 lb/MWh, but still cannot achieve the standard without the use of CHP credits or additional emission controls.

Federal New Source Performance Standards (NSPS) such as 40 CFR Part 60, Subpart KKKK, are essentially a technology "floor" for new and modified equipment. The NSPS standards do not take into account local issues with air quality, such as the commission's current efforts to address ozone nonattainment in Texas. A standard permit is required to consider protection of human health and the environment in more specific ways than federal NSPS regulations. It is not unusual for control requirements associated with NSR permits and standard permits to exceed control requirements of federal NSPS regulations. Concerning the Solar Mercury turbine, although the commission does not yet have test data on that model, it is anticipated that the installed performance of the unit may achieve the 0.14 lb/MWh standard directly, without use of CHP or additional controls. However, the commission expects that, in most installations, CHP would be applied to recover waste heat, which would further facilitate compliance with the standard. No changes have been made in response to this comment.

Good Company Associates commented that the 0.14 lb/MWh standard is the most restrictive NO_x emissions requirement for distributed generation systems in the country, and that this stringent emission limit is hindering the Texas market for distributed generation. Good Company Associates commented that a relaxed emission standard for distributed generation could actually result in an overall reduction of NO_x emissions, citing a 2003 study by Hadley and Van Dyke of the Oak Ridge National Laboratory. The study showed that even if the NO_x emission limit for distributed generation was increased, those distributed generation emissions would be offset by reduced emissions from relatively high-emitting "peaking" power plants.

The commission acknowledges that the 0.14 lb/MWh standard is aggressive for small units, but emission limitations in other states with similar air pollution concerns are also becoming more stringent. For example, the California Air Resources Board's 2007 NO_x emission standard for distributed generation certification is 0.07 lb/MWh. As an overall performance level, 0.14 lb/MWh is equivalent to BACT for large gas-fired power plants, and this BACT level has been applied for a number of years. Distributed generation projects that cannot meet the standard permit can be authorized using the standard case-by-case NSR permitting process. The commission does not dispute the possibility that a higher NO_x emission limit in the standard permit could allow faster implementation of distributed generation in Texas, and could conceivably result in lower overall NO_x emissions. However, the complexity of determining the net effect, and the difficulty in enforcing the reductions at peaking units, make it difficult to rely on such a strategy for regulatory purposes. No changes were made in response to this comment.

Good Company Associates commented that the East Texas NO_x emission limit for units less than 10 MW should be restored to the 0.47 lb/MWh standard, with a step down to 0.30 lb/MWh in the year 2010. Good Company Associates commented that the standard could be reduced to 0.15 lb/MWh in 2012 following an appropriate technical review.

Although the commission appreciates the commenter's proposal of specific emission standards, the commission does not agree with the commenter's suggested emission standards and associated timelines. The maintenance of the 0.47 lb/MWh standard until 2010, and the suggested step down to 0.30 lb/MWh, are not reflective of the NO_x performance that can be achieved with current technology. Although not all equipment can meet the limits in the standard permit, sufficient technology is available to allow projects to be implemented in compliance with the standard permit. The standard permit is intended to promote the use of clean technology, especially in the East Texas region where NO_x is a major concern as an ozone precursor. If an applicant has a need to use equipment that is unable to meet the emission limits in the standard permit, that equipment can be authorized under the case -by-case NSR permitting process.

EMA indicated general support for amending the NO_x emission limit for units burning landfill, digester, and stranded oilfield gas. This limit was proposed to be increased from 1.77 lb/MWh to 1.90 lb/MWh. However, EMA recommended a NO_x emission limit of 9.3 lb/MWh, to ensure that waste-to-energy projects can be successfully installed and operated, and to ensure the maximum benefits of waste-to-energy projects can be realized. EMA commented that this higher emission limit is necessary due to the large variability in these types of fuels and the technical infeasibility of catalyst based aftertreatment.

The commission does not concur with EMA's proposed NO_x emission limit of 9.3 lb/MWh for units burning landfill, digester, and stranded oilfield gas. The proposed adjustment to 1.90 lb/MWh is necessary to account for efficiency losses that were not accounted for in the original standard permit, but the proposed adjustment does not reflect a fundamental change in the expected NO_x performance of units under the standard permit. The commission believes that EMA's proposed increase to 9.3 lb/MWh is not reflective of the NO_x performance many units are already achieving, and could potentially result in substantial NO_x emissions in the East Texas area. The commission declines to make the suggested change.

Solar Turbines, Inc. commented that, although the proposed 1.90 lb NO_x/MWh emission limit for units burning landfill, digester, and stranded oilfield gas would be an improvement over the current emission limit, the proposed 1.90 lb/MWh limit would preclude some common alterative fuels from qualifying for the standard permit. Solar Turbines, Inc. recommended a limit of 5.5 lb/MWh. Solar Turbines, Inc. commented that turbines burning alternative fuels have a wide-ranging emissions profile, due to the variability in the fuel characteristics.

The commission acknowledges that some fuels may not be capable of meeting the proposed 1.90 lb/MWh emission limit. However, the standard permit is not intended to cover all

applications. Although an emission limit of 5.5 lb/MWh could allow a wider range of fuels, the potential NO_x emissions resulting from such a limit could be excessive in the sensitive East Texas area. The proposed 1.90 lb/MWh standard is sufficient to cover most landfill, digester, and oilfield applications, while maintaining an appropriate degree of NO_x control. Situations which are not able to meet the conditions of the standard permit may be authorized under a case-by-case NSR permit, where the control technology and environmental impacts can be reviewed in detail.

Solar Turbines, Inc. also commented that the standard permit should specify that the emission limits only apply at full load, plus a nominal range such as +/- 10%.

The commission acknowledges that EGUs operating at reduced load may have difficulty meeting the output-based emission standards. The emission standards in the standard permit were intended to apply to units operating at or near their intended design load. The commission does not support the complete elimination of emission limits for conditions of reduced load, but the commission has added a provision under new subsection (4)(H) to provide more flexibility for units operating at reduced load. If the unit is operating at less than 80% of rated load, the modified NO_x emission standard will be determined by multiplying the unit's rated output (in MW) by the applicable NO_x emission limit in subsections (4)(D)-(4)(F). This will result in an hourly NO_x emission limit in lb/hour, which would be equivalent to the NO_x mass emission rate that the unit would be allowed at full load. Owners or operators must maintain records to demonstrate that the unit meets the lb/hr NO_x emission limit under reduced load operating conditions.

Solar Turbines, Inc. also commented that the emission limits should only apply at ambient temperatures above 0 degrees Fahrenheit, as is typically warranted by the manufacturers.

The commission acknowledges that extremely low ambient temperatures can have a detrimental effect on emissions, and some manufacturers will not certify or warranty emissions performance under those conditions. The commission has added a provision under new subsection (4)(H) to specify that the NO_x emission limits do not apply when ambient temperatures at the location of the EGU are below zero degrees Fahrenheit.

Solar commented that Section (3)(E) of the standard permit should include a reference to 40 CFR Part 60, Subpart KKKK for new, modified, and reconstructed units.

The commission concurs with the comment and has made a change to the standard permit to reference Subpart KKKK.

Good Company Associates commented that wider application of distributed generation can reduce overall energy consumption, by recovering waste heat, and/or by reducing line power losses that result from delivering power from a remote centralized power station. Good Company stated that the line losses average 5 - 10%, and can exceed 25% on hot days. Good Company recommended that TCEQ and Texas A&M Energy Systems Laboratory use modeling to quantify the energy efficiency benefits of distributed generation and treat the reduced line losses as SIP-creditable emission reductions.

This comment does not directly relate to the proposed changes to the standard permit. This comment concerns emissions calculations related to the SIP, which is not an appropriate subject matter for consideration in adopting the amendments to the electric generating unit standard permit. No changes to the standard permit were made in response to this comment.

Good Company Associates commented that wider implementation of distributed generation could help manage load and prevent rolling blackouts, such as the event on April 17, 2006.

Although the commission concurs that appropriate implementation of distributed generation can improve the reliability of the state's electric grid, the commission's primary responsibility is to address the environmental factors associated with authorizing EGUs. No changes were made in response to this comment.

IX. STATUTORY AUTHORITY

This standard permit is issued under the Texas Health and Safety Code (THSC), § 382.011, General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC § 382.051, Permitting Authority of Commission; Rules, which authorizes the commission to issue permits, including standard permits for similar facilities; THSC § 382.0513, Permit Conditions, which authorizes the commission to establish and enforce permit conditions consistent with Subchapter C of the Texas Clean Air Act; and THSC § 382.05195, Standard Permit, which authorizes the commission to issue standard permits according to the procedures set out in that section.

Air Quality Standard Permit for Electric Generating Units
Effective Date May 16, 2007

This standard permit authorizes electric generating units that generate electricity for use by the owner or operator and/or generate electricity to be sold to the electric grid, and that meet all of the conditions listed below.

(1) Applicability

(A) This standard permit may be used to authorize electric generating units installed or modified after the effective date of this standard permit and that meet the requirements of this standard permit.

(B) This standard permit may not be used to authorize boilers. Boilers may be authorized under the Air Quality Standard Permit for Boilers; 30 TAC § 106.183, Boilers, Heaters, and Other Combustion Devices; or a permit issued under the requirements of 30 TAC Chapter 116.

(2) Definitions

(A) East Texas Region - All counties traversed by or east of Interstate Highway 35 or Interstate Highway 37, including Bosque, Coryell, Hood, Parker, Somervell and Wise Counties.

(B) Installed - a generating unit is installed on the site when it begins generating electricity.

(C) West Texas Region - Includes all of the state not contained in the East Texas Region.

(D) Renewable fuel - fuel produced or derived from animal or plant products, byproducts or wastes, or other renewable biomass sources, excluding fossil fuels. Renewable fuels may include, but are not limited to, ethanol, biodiesel, and biogas fuels.

(3) Administrative Requirements

(A) Electric generating units shall be registered in accordance with 30 TAC § 116.611, Registration to Use a Standard Permit, using a current Form PI-1S. Units that meet the conditions of this standard permit do not have to meet 30 TAC § 116.610(a)(1), Applicability.

(B) Registration applications shall comply with 30 TAC § 116.614, Standard Permit Fees, for any single unit or multiple units at a site with a total generating capacity of 1 megawatt (MW) or greater. The fee for units or multiple units with a total generating capacity of less than 1 MW at a site shall be $100.00. The fee shall be waived for units or multiple units with a total generating capacity of less than 1 MW at a site that have certified nitrogen oxides (NO_x) emissions that are less than 10 percent of the standards required by this standard permit.

(C) No owner or operator of an electric generating unit shall begin construction and/or operation without first obtaining written approval from the executive director.

(D) Records shall be maintained and provided upon request to the Texas Commission on Environmental Quality (TCEQ) for the following:

(i) Hours of operation of the unit;

(ii) Maintenance records, maintenance schedules, and/or testing reports for the unit to document re-certification of emission rates as required by subsection (4)(G) below; and

(iii) Records to document compliance with the fuel sulfur limits in subsection (4)(C).

(E) Electric generators powered by gas turbines must meet the applicable conditions, including testing and performance standards, of Title 40 Code of Federal Regulations (CFR) Part 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, and applicable requirements of 40 CFR Part 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines.

(F) Compliance with this standard permit does not exempt the owner or operator from complying with any applicable requirements of 30 TAC Chapter 117, Control of Air Pollution from Nitrogen Compounds, or 30 TAC Chapter 114, Control of Air Pollution from Motor Vehicles.

(4) General Requirements

(A) Emissions of NO_x from the electric generating unit shall be certified by the manufacturer or by the owner or operator in pounds of pollutant per megawatt hour (lb/MWh). This certification must be displayed on the name plate of the unit or on a label attached to the unit. Test results from U.S. Environmental Protection Agency (EPA) reference methods, California Air Resources Board methods, or equivalent alternative testing methods approved by the executive director used to verify this certification shall be provided upon request to the TCEQ. The unit must operate on the same fuel(s) for which the unit was certified.

(B) Electric generating units that use combined heat and power (CHP) may take credit for the heat recovered from the exhaust of the combustion unit to meet the emission standards in subsections (4)(D), (4)(E), and (4)(F). Credit shall be at the rate of one MWh for each 3.4 million British Thermal Units of heat recovered. The following requirements must be met to take credit for CHP for units not sold and certified as an integrated package by the manufacturer:

(i) The owner or operator must provide as part of the application documentation of the heat recovered, electric output, efficiency of the generator alone, efficiency of the generator including CHP, and the use for the non-electric output, and

(ii) The heat recovered must equal at least 20 percent of the total energy output of the CHP unit.

(C) Fuels combusted in these electric generating units are limited to:

(i) Natural gas containing no more than ten grains total sulfur per 100 dry standard cubic feet;

(ii) Landfill gas, digester gas, stranded oilfield gas, or gaseous renewable fuel containing no more than 30 grains total sulfur per 100 dry standard cubic feet; or

(iii) Liquid fuels (including liquid renewable fuel) not containing waste oils or solvents and containing less than 0.05 percent by weight sulfur.

(D) Except as provided in subsections (4)(F) and (4)(H), NO_x emissions for units 10 MW or less shall meet the following limitations based upon the date the unit is installed and the region in which it operates:

East Texas Region:

(i) Units installed prior to January 1, 2005 and

(a) operating more than 300 hours per year - 0.47 lb/MWh;

(b) operating 300 hours or less per year - 1.65 lb/MWh;

(ii) Units installed on or after January 1, 2005 and

(a) operating more than 300 hours per year, with a capacity greater than 250 kilowatts (kW) - 0.14 lb/MWh;

(b) operating 300 hours or less per year - 0.47 lb/MWh; or

(c) any unit with a capacity of 250 kW or less - 0.47 lb/MWh.

West Texas Region:

(i) Units operating more than 300 hours per year - 3.11 lb/MWh;

(ii) Units operating 300 hours or less per year - 21 lb/MWh. Units certified to comply with applicable Tier 1, 2, or 3 emission standards in 40 CFR Part 89, Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines, are deemed to satisfy this emission limit.

(E) Except as provided in subsections (4)(F) and (4)(H), NO_x emissions for units greater than 10 MW shall meet the following limitations:

(i) Units operating more than 300 hours per year - 0.14 lb/MWh;

(ii) Units operating 300 hours or less per year - 0.38 lb/MWh.

(F) Electric generating units firing any gaseous or liquid fuel that is at least 75 percent landfill gas, digester gas, stranded oil field gas, or renewable fuel content by volume, shall meet a NO_x emission limit of 1.90 lb/MWh. Units in West Texas with a capacity of 10 MW or less that fire at least 75 percent landfill gas, digester gas, stranded oilfield gases, or gaseous or liquid renewable fuel by volume, must comply with the applicable West Texas NO_x limit in subsection (4)(D).

(G) To ensure continuing compliance with the emissions limitations, the owner or operator shall re-certify a unit every 16,000 hours of operation, but no less frequently than every three years. Re-certification may be accomplished by following a maintenance schedule that the manufacturer certifies will ensure continued compliance with the required NO_x standard or by third party testing of the unit using appropriate EPA reference methods, California Air Resources Board methods, or equivalent alternative testing methods approved by the executive director to demonstrate that the unit still meets the required emission standards.

After re-certification, the unit must operate on the same fuel(s) for which the unit was re-certified.

(H) The NO_x emission limits in subsections (4)(D)-(4)(F) are subject to the following exceptions:

(i) The hourly NO_x emission limits do not apply at times when the ambient air temperature at the location of the unit is less than 0 degrees Fahrenheit.

(ii) At times when a unit is operating at less than 80% of rated load, an alternative NO_x emission standard for that unit may be determined by multiplying the applicable emission standard in subsections (4)(D)-(4)(F) by the rated load of the EGU (in MW), to produce an allowable hourly mass NO_x emission rate. In order to use this alternative standard, an owner or operator must maintain records that demonstrate compliance with the alternative emission standard, and make such records available to the TCEQ or any local air pollution control agency with jurisdiction upon request.