The Texas Commission on Environmental Quality (TCEQ, agency, or commission) adopts new §106.513 *with change* to the proposed text as published in the March 9, 2012, issue of the *Texas Register* (37 TexReg 1649).

Background and Summary of the Factual Basis for the Adopted Rule

House Bill (HB) 3268, 82nd Legislature, 2011, requires the commission to adopt a permit by rule (PBR) or issue a standard permit to authorize stationary natural gas engines and turbines that are used as part of a combined heat and power (CHP) system. A CHP system is one in which heat resulting from the operation of the engine or turbine, which is typically wasted, is recovered and used for another purpose such as heating water or providing cooling for facility operations. The requirements of HB 3268 are codified in Texas Health and Safety Code (THSC), §382.051865. HB 3268 requires that TCEQ adopt any rules necessary to implement THSC, §382.051865 no later than September 1, 2012.

THSC, §382.051865 states that TCEQ may consider the following factors in the development of the PBR or standard permit for stationary natural gas CHP units: 1) the geographic location where a stationary natural gas CHP unit may be used, including proximity to nonattainment areas; 2) the annual operating hours of a stationary natural gas CHP unit; 3) the technology used by a stationary natural gas CHP unit; 4) the types of fuel used by a stationary natural gas CHP unit; and 5) other emission control policies

of the state. THSC, §382.051865 also states that the PBR or standard permit may not distinguish between the end-use functions powered by a stationary natural gas CHP engine or turbine, and that the emission limits shall be structured in terms of air contaminant emissions per unit of total energy output. THSC, §382.051865(f) specifies that TCEQ shall consider both the primary and secondary functions of the unit when determining the emissions per unit of energy output.

TCEQ determined that the most efficient manner to implement HB 3268 would be to adopt a PBR to authorize units covered by the legislation, rather than to develop a standard permit. The TCEQ adopted the current version of the air quality standard permit for electric generating units (EGUs) in 2007, which included a credit to help CHP units achieve the best available control technology (BACT) emission standards of the standard permit. Several CHP stakeholders have commented that smaller CHP units are not usually designed to incorporate the add-on controls that the standard permit envisions. Therefore, the TCEQ has chosen to use the PBR for insignificant sources as a means of authorizing these smaller CHP units while continuing to minimize emissions from the industry.

Section Discussion

§106.513, Natural Gas Combined Heat and Power Units

The commission adopts new §106.513, to authorize natural gas-fired CHP units as

outlined by HB 3268 and THSC, §382.051865. This PBR is not intended to cover all possible scenarios relating to CHP operations, but it addresses the most common applications within the scope established by HB 3268. Any particular facility that does not meet the general or specific conditions of the PBR may apply for a case-by-case air permit under 30 TAC Chapter 116, Control of Air Pollution by Permits for New Construction or Modification. The air quality standard permit for EGUs is another option available to authorize CHP units that meet the applicable requirements of the standard permit.

Section 106.513(a)(1) establishes the applicability of this PBR to CHP units or combinations of units that are primarily powered by pipeline-quality natural gas. The proposed rule was limited to units which generated up to 5 megawatts (MW), but in response to comments, the commission has increased the maximum capacity which may be authorized under the PBR. The proposed language concerning the maximum allowed capacity under the PBR has been removed from §106.513(a)(1). Requirements relating to the capacity of units under this PBR have been relocated to §106.513(c)(5).

As stated in §106.513(a)(1), the primary fuel type authorized under the proposed PBR is pipeline-quality natural gas, although in response to comments, the commission has added language in §106.513(c)(8) to allow for the use of certain other fuels on an emergency basis. CHP units fueled by landfill or other biogas fuels have been authorized

under the air quality standard permit for EGUs, and applicants using such fuels may continue to use that authorization.

Section 106.513(a)(1) also includes language to clarify that the PBR authorizes any fugitive components associated with the CHP unit (such as piping, valves, and connectors) used to supply fuel to the authorized CHP unit. Pipeline-quality natural gas is composed predominantly of methane, with lesser amounts of ethane, propane, nitrogen, carbon dioxide, and trace amounts of hydrogen sulfide. In the quantities that would be emitted from normal fugitive emission sources, these compounds are not a significant risk to human health or the environment. Therefore, air quality impacts from fugitive components will be negligible, and the requirements of the PBR are protective.

Section 106.513(a)(2) states that facilities authorized under this PBR may be subject to other rules and regulations, and this PBR does not relieve the owner or operator from complying with any other applicable requirements. CHP units authorized under this PBR must comply with the requirements in Chapter 106, Subchapter A, General Requirements, including but not limited to the emission limitations in §106.4, Requirements for Permitting by Rule. Meeting the general requirements and requirements specific to this PBR ensures that ambient air quality standards are achieved and that facilities will not emit pollutants in amounts that will contribute significantly to nonattainment areas or interfere with maintenance areas.

Examples of other rules and regulations that may apply to engines and turbines include, but are not limited to, 30 TAC Chapter 117, Control of Air Pollution from Nitrogen Compounds; and various federal regulations such as 40 Code of Federal Regulations (CFR) Part 60, Subparts GG, IIII, JJJJ, and KKKK; and 40 CFR Part 63, Subparts YYYY and ZZZZ.

Section 106.513(b) establishes definitions of key terms used in this section, including a definition of a "CHP unit" and of "pipeline quality natural gas." The definition of "CHP unit" has been revised in response to comments in order to allow for the recovery of heat from sources other than the EGU exhaust (such as heat recovered from the cooling system of an engine). The definition of "pipeline quality natural gas" is similar to the definition used in federal regulations such as 40 CFR Part 60, Subpart JJJJ, Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. Sour gas as defined in 30 TAC §101.1, Definitions, may not be used as a fuel under this PBR.

Section 106.513(c) establishes general conditions applicable to CHP units authorized under this section. Section 106.513(c)(1) specifies that a CHP unit must be registered with the commission using the appropriate PI-7 form, or an approved electronic method, before start of construction. However, a CHP unit at a residential location that generates less than 20 kilowatts (kW) of electricity does not have to be registered or

meet any other requirements except for §106.513(a) and (c)(2), which define applicability of the PBR and specify the required minimum level of heat recovery. For units that require registration, the registration will be processed and reviewed by the Air Permits Division. Although non-residential units that generate less than 20 kW are required to register, those units are exempt from the emission standards and associated monitoring and testing requirements. Units with a capacity of less than 20 kW are not anticipated to have a significant impact on human health or the environment.

Section 106.513(c)(2) establishes a minimum required level of heat recovery for units authorized under this section. The heat recovered must equal at least 20% of the total heat energy output of the CHP unit. This means that a minimum of 20% of the available heat must be recovered and used elsewhere. This requirement must be met continuously based on any one calendar week of operation, except for no more than two weeks in any rolling 52-week period if operation of the EGU component is necessary due to lack of available electricity. This provides flexibility for situations where the CHP unit is the only available source of power. The commission is specifying a minimum required level of heat recovery to ensure that this PBR is only used for projects that have a significant CHP component.

Section 106.513(c)(3) specifies that no owner or operator of a CHP unit that is subject to the registration requirement may begin construction or operation without first

obtaining written approval from the executive director. The commission requires written approval because CHP units can be complex, capital-intensive projects, and it can be difficult or impractical to retrofit a unit to meet standards for which it was not initially designed. Pre-approval would ensure that registrants avoid the need to order different equipment to satisfy the PBR or other applicable standards, reducing financial risk. Since PBR registrations are processed in a relatively short time, no significant burden on registrants is anticipated due to the pre-approval requirement.

Section 106.513(c)(4) prohibits the use of add-on pollution controls to meet the emission limitations of this PBR, except for oxidation-reduction (three-way) catalysts on rich-burn engines, and oxidation catalyst controls as required by §106.513(d)(3) or (4). Newer regulations written for rich-burn reciprocating engines already require or assume the installation of a three-way catalyst and generally this represents BACT for rich-burn engines. Catalyst operation is relatively uncomplicated and has a long service period interval. Lean-burn reciprocating engines and turbines should only use the CHP credit allowed under §106.513(d)(5) to comply with the emission standards without regard to add-on controls (except for any units subject to the oxidation catalyst requirement of §106.513(d)(3) or (4)). Add-on controls may be used for other reasons, but those controls must not be taken into account when registering or demonstrating compliance with this PBR.

Section 106.513(c)(5) contains restrictions on the capacity of units authorized under this PBR, in some cases. A single unit cannot exceed 15 MW in capacity. A group of units which are in close proximity (as specified in §106.513(c)(7)(B)) is also collectively limited to a total capacity of 15 MW, for that group. These restrictions are necessary to ensure that applicable air quality standards are met. However, note that a total site capacity exceeding 15 MW is still possible, for some situations. For example, two individual units with a capacity of 15 MW each would be allowed if the units are at least 900 feet apart, and the applicable emission limitations and control requirements are met. Similarly, multiple groups of units with a per-group capacity of 15 MW or less, that are separated by at least 900 feet, would also be allowed. However, all facilities must still meet the overall limitations of §106.4, which could become a limiting factor for multiple larger units or groups of units.

Section 106.513(c)(6) has been added to clarify that a site cannot use multiple registrations of §106.513; only one registration is allowed per site. This restriction is necessary as the PBR has been revised to potentially allow for multiple CHP units under a single registration.

Section 106.513(c)(7) restricts the use of this PBR to one CHP unit at a given site, except for certain defined scenarios. This restriction is necessary to prevent excessive cumulative impacts from multiple sources. In response to comments, the commission

has added several specific scenarios under which multiple units may be authorized under the PBR.

Section 106.513(c)(7)(A) covers the first scenario where multiple units are allowed. Units with a capacity less than 20 kW are not restricted in number or in location at the site. In addition, units with a capacity of less than 20 kW are not required to be considered when applying the distance criteria in §106.513(c)(7)(B) or (C). However, the capacity of any sub-20 kW units must still be included when determining the total combined capacity of all units under the PBR, for purposes of determining the applicable emission standard under §106.513(d)(2), (3), or (4).

The second scenario covering multiple units is addressed in §106.513(c)(7)(B). Multiple units are allowed if the stack emission points associated with all the units are all located within a circular area with a radius of not more than 200 feet, and the total capacity of the group of units does not exceed 15 MW. Units with a capacity of less than 20 kW are not required to be considered when applying the distance criteria of this subparagraph. For example, the presence of one or more units with a capacity of less than 20 kW outside the defined area does not invalidate the use of this subparagraph for other units.

The third scenario covering multiple units is addressed in §106.513(c)(7)(C). Under this scenario, multiple units are allowed if the stack emission points of all units are separated

by a distance of at least 900 feet. Section 106.513(c)(7)(C) also allows for multiple groups of units. For example, this would allow a scenario where a group of units meeting the 200-foot radius criteria of §106.513(c)(7)(B) is separated from another unit (or group of units) by a distance of at least 900 feet. This essentially allows multiple clusters of units so long as the individual groups meet §106.513(c)(7)(B) and the separation between the clusters is at least 900 feet per §106.513(c)(7)(C). Units with a capacity of less than 20 kW are not required to be considered when applying the distance criteria of this subparagraph. For example, the presence of one or more units with a capacity of less than 20 kW within 900 feet of another unit does not invalidate the use of this subparagraph.

The commission added §106.513(c)(8) in response to comments requesting that the PBR allow for more flexibility in the fuels which could be used. Section 106.513(c)(8) allows for the use of propane, liquefied petroleum gas (LPG), gasoline, diesel, or fuel oil as approved fuels in the event of an emergency that precludes the availability of pipeline quality natural gas. The use of these emergency fuels is limited to 720 hours in any 365-day period. The commission has also allowed for brief periods of operation on these fuels for purposes of maintenance or testing of the unit, not to exceed two hours in any seven-day period. The commission anticipates that this allowance for emergency fuels will be infrequently used, as it typically would require a relatively severe event to cause widespread loss of natural gas. In addition, many industrial engines or turbines

designed for operation on natural gas may not be capable of operating on fuels like diesel or fuel oil. Unlike diesel backup generators, CHP units are expected to run continuously on natural gas and would only require the use of an emergency fuel if both natural gas and the electric grid were both unavailable, a very unlikely scenario.

Section 106.513(d) establishes emission standards and control requirements for CHP units authorized under this section. These emission standards are based on the maximum electrical production capacity of the unit (or combination of units, where applicable). The term "any combination of units" as used in §106.513(d)(2) - (4) is referring to the collection of all CHP units at the site.

Section 106.513(d)(1) specifies that any unit with a capacity under 20 kW is exempt from the emission standards and control requirements otherwise required in §106.513(d). However, when multiple units are to be authorized, any sub-20 kW units must still be included when determining the total generating capacity at the site for purposes of determining the applicability of §106.513(d)(2), (3), or (4) to units 20 kW or larger. Units producing less than 20 kW also remain subject to the general emission limitations contained in §106.4.

Section 106.513(d)(2) establishes a nitrogen oxides (NO_X) emission standard of 1.0 pound (lb)/megawatt-hour (MWh) for units (or combinations of units) with a capacity

greater than or equal to 20 kW, and less than or equal to 8 MW. The carbon monoxide (CO) emission standard for this category is 9.0 lb/MWh. The commission has determined that units of 8 MW or less which comply with these emission limitations will meet applicable National Ambient Air Quality Standards (NAAQS) without additional control.

Section 106.513(d)(3) establishes emission standards and control requirements for the scenario where a CHP unit (or combination of units) has a capacity greater than 8 MW. Under this scenario, the unit or units is required to meet a NO_X emission standard of 0.7 lb/MWh, and a CO emission standard of 9.0 lb/MWh. The more stringent NO_X emission standard is necessary to ensure that units of this capacity meet applicable NAAQS for nitrogen dioxide (NO_2). In addition, the commission requires a unit or units under this category to be equipped with an oxidation catalyst control device, primarily to ensure compliance with applicable NAAQS for particulate matter with an aerodynamic diameter less than 2.5 micrometers ($PM_{2.5}$). Note that if multiple facilities are to be authorized under this paragraph, they must meet the distance criteria of §106.513(c)(7)(B), which requires that all stack emission points associated with the units are located within a circular area with a radius of not more than 200 feet.

Section 106.513(d)(4) establishes emission standards and control requirements for the scenario where a combination of CHP units has a total capacity greater than 8 MW, and

the distance between the units (or groups of units) is at least 900 feet. Under this scenario, units with a capacity of 8 MW or less are subject to a NO_X emission standard of 1.0 lb/MWh, and a CO emission standard of 9.0 lb/MWh. However, any units with a capacity exceeding 8 MW are required to meet a NO_X emission standard of 0.7 lb/MWh, and are also required to be equipped with an oxidation catalyst control device. When one or more groups of closely-spaced units meeting the requirements of §106.513(c)(7)(B) are present, the group shall be considered one unit for the purposes of determining the applicable emission standard under this paragraph. For example, a group of closely-spaced units with a total capacity of 12 MW would be subject to the 0.7 lb/MWh standard and the oxidation catalyst control requirement. Each unit in such a group would be subject to the oxidation catalyst control requirement. A group with a total capacity of 8 MW or less would be subject to the 1.0 lb/MWh standard, and would not be subject to the oxidation catalyst control requirement. As previously discussed, the more stringent requirements on the larger units are needed to ensure compliance with applicable NAAQS.

Section 106.513(d)(5) establishes that for each 3.4 million British Thermal Units (MM Btu) of heat recovered, a CHP credit of 1 MW is provided. The CHP credit allows for the energy recovered by the CHP system to be considered when determining compliance with the emission standards. The rule language has been revised slightly in response to a comment in order to allow for heat recovery from waste heat sources other than the unit

exhaust. The purpose of this PBR is to allow CHP units to take into account the benefit of recovering energy from waste heat and preventing the need for consuming more fuel or electricity to perform functions such as heating or cooling a building. When the energy from the heat recovery system is considered in addition to the electric power output, the effective pollutant rate per MWh is decreased.

For example, a CHP unit with an electrical output capacity of 5 MW, and heat recovery of 6 MM Btu/per hour (h), (assuming this is at least 20% recovery and qualifies for the CHP credit) could have an emission rate of:

1.0 lb/MWh x {1 + ((6 MMBtu/h) /(3.4 MMBtu/MWh x 5 MW))}= 1.35 lb NO_X/MWh.

Because of the CHP credit, the 5 MW EGU component in this example could actually emit 1.35 lb NO_X/MWh before accounting for the CHP credit and still be in compliance with the 1.0 lb NO_X/MWh emission standard.

Section 106.513(e) contains monitoring and testing requirements that are necessary to ensure that the authorized facility or facilities meets the applicable emission standards. As with all compliance demonstrations, sampling and monitoring of facility performance and emission rates are the responsibility of the owner or operator of the facility. Section 106.513(e)(1) applies to internal combustion engine-based CHP units only (not turbines). This paragraph requires that, beginning no later than 180 calendar

days after startup, the owner or operator will analyze NO_X and CO emissions from the CHP unit using a portable analyzer, in order to confirm that the unit is operating in compliance with the applicable emission standards. After the initial test, the owner or operator is required to analyze the emissions at least twice per calendar year on an ongoing basis. This monitoring requirement does not apply to CHP units with an electricity output of less than 20 kW, which are not subject to an emission standard under this section. Engines that are operated for 1,000 hours or less during the applicable half-year period are not required to be tested for that period.

Section 106.513(e)(2) applies to engine and turbine-based CHP systems that are subject to an emission standard under §106.513(d). If the unit is not certified to meet the applicable emission standard(s) by the manufacturer according to an approved United States Environmental Protection Agency (EPA) testing protocol, the unit must be tested within 90 days of startup for NO_X and CO, using an appropriate reference method, or an alternative method approved by the executive director. All EGUs that have a capacity to generate more than 375 kW must be retested after every 16,000 hours of operation, regardless of certification status.

Section 106.513(e)(3) contains requirements for testing CHP units which are equipped with an oxidation catalyst, as is required under §106.513(d)(3) or (4)(B). The testing must verify compliance with the required 70% volatile organic compounds (VOC)

control efficiency, and must be conducted within 90 days of startup. A retest is required for every 16,000 hours of operation. In lieu of the test method used for VOC sampling, the use of gaseous organic compound test methods (such as Method 25A) are allowed if the reduction is shown to be at least 90%. This allows for use of a less expensive test method while the higher efficiency accounts for the fact that easily oxidized methane and ethane would also be factored into the reduction.

Section 106.513(e)(4) specifies that, except for rich-burn engines equipped with oxidation-reduction (three-way) catalysts, and units subject to the oxidation catalyst requirement in §106.513(d)(3) or (4)(B), the uncontrolled source must be used in demonstrating compliance with the emission standards in §106.513(d).

Section 106.513(f) contains recordkeeping requirements that are necessary so that TCEQ and any local pollution control agency with jurisdiction can verify that the CHP unit is operating in compliance with the applicable emission standards and with the minimum heat recovery requirements. Owners or operators are required to maintain records to demonstrate that the CHP unit is in compliance with any run-time based requirements, such as the exemption from testing for units that operate less than or equal to 1,000 hours in an applicable half-year period in §106.513(e)(1)(B), or the 16,000 hour retest requirement in §106.513(e)(2) or (3). Owners or operators are also required to maintain records of planned maintenance activities authorized under §106.513(g)(2), and records

of any periods of emergency fuel used under §106.513(c)(8).

Section 106.513(g) authorizes emissions from planned maintenance, startup, and shutdown activities that are typical for engines and turbines. Under §106.513(g)(1), emissions resulting from startup and shutdown operations of CHP units are authorized under this PBR. Section 106.513(g)(2) authorizes emissions resulting from planned maintenance. These planned maintenance activities include, but are not limited to, filter changes, oxygen sensor replacements, overhauls, lubricant changes, spark plug changes, and emission control system maintenance. This section also authorizes other maintenance activities that are routine for engines and turbines in a CHP application.

In developing this PBR, all expected air emissions from CHP units of 15 MW or less, equipped with any required controls, were evaluated for compliance with applicable state and federal air quality standards and state guideline effects screening levels (ESLs). Emissions from point sources were evaluated using the ISC-Prime model, and fugitive emissions of hydrogen sulfide were evaluated using the SCREEN3 model. The commission determined that applicable NAAQS, state standards for sulfur dioxide (SO_2) and hydrogen sulfide, and state ESLs would be met.

The commission estimated maximum ground level concentrations of the products of combustion (formaldehyde, particulate matter including particulate matter with a diameter of 10 microns and less and 2.5 microns and less ($PM/PM_{10}/PM_{2.5}$), SO_2, NO_X,

and CO) using fuel consumption rates for $PM/PM_{10}/PM_{2.5}$ and SO_2, and emission standards for NO_X and CO for the types of CHP unit configurations expected.

Small units less than 1 MW are expected to be mostly reciprocating engine-based and units larger than 1 MW are expected to be turbine-based. An engine with a stack height of 8 feet, exit temperature of 900 degrees Fahrenheit, exit velocity of 83.5 feet per second (fps), and diameter of 1 foot represents CHP units less than 1 MW. A turbine with a stack height of 20 feet, exit temperature of 950 degrees Fahrenheit, exit velocity of 112 fps, and diameter of 2.5 feet represents CHP units greater than 1 MW.

The air quality analysis (AQA) determined the pollutant emissions meet all applicable NAAQS, state standards, and state ESLs for CHP units 8 MW or less (and 15 MW or less, for units equipped with an oxidation catalyst control device). This result is consistent with previous Air Permits Division permitting experiences that sites with only one or two small engines or a small turbine fired on pipeline-quality natural gas do not cause or contribute to exceedances of air quality standards or guideline ESLs. The AQA was performed using ISC-Prime (Version 04272). The ISC model has been used in permitting for more than 20 years. The model was developed to be easy to use and address complex atmospheric processes in a relatively simple way that can be understood by all users. The ISC model is based on the Gaussian distribution equation and is inherently conservative due to the main simplifying assumptions made in its

derivation: conditions are steady-state (for each hour, emissions, wind speed, and direction are constant) and the dispersion from source to receptor is effectively instantaneous; there is no plume history as model calculations in each hour are independent of those in other hours; mass is conserved (no removal due to interaction with terrain, deposition, or chemical transformation) and is reflected at the surface; and plume spread from the centerline follows a normal Gaussian distribution and only vertical and crosswind dispersion occurs, dispersion downwind is ignored. The model was applied in a screening mode to ensure predictions were conservative and applicable for any location in the state.

Both rural and urban dispersion coefficients and flat terrain were used in the modeling. The higher of the predicted concentrations between rural and urban dispersion coefficients is reported as the maximum ground-level concentration (GLCmax).

The AQA used a polar receptor grid with 36 radials spaced every 10 degrees from true north. Receptors were located on each radial at distances of 100, 150, and 200 feet; every 100 feet out to 3,000 feet; and every 500 feet out to 5,500 feet from the sources.

Surface data from Austin and upper air data from Victoria for the years 1983, 1984, 1986, 1987, and 1988 was used in the AQA. Since the analysis is primarily for short-term concentrations, this five-year data set would include worst-case short-term

meteorological conditions that could occur anywhere in the state. The wind directions were used at 10 degree intervals to be coincident with the receptor radials. This would provide predictions along the plume centerline, giving a conservative result.

Since the CHP units can be installed on or next to buildings, modeling was conducted with and without downwash. The modeling with downwash was the controlling scenario and used in the AQA. Building Profile Input Program Prime (Version 04274) was used to compute downwash parameters for a generic building. The generic building represented in the AQA has a length of 100 feet and width of 100 feet. The height of the building ranged from 30 feet to 250 feet.

Reasonable worst-case stack parameters were derived from a review of industry sources. Exhaust stacks were modeled as point sources with release heights of 8 feet and 20 feet. The engine and turbine parameters represented in the AQA are listed in the following table.

Figure: 30 TAC Chapter 106 preamble-1

Source	Stack Height (feet)	Stack Temp (Fahrenheit)	Flow (actual cubic feet per	Stack Exit Velocity (feet per	Diameter (feet)

			minute)	second)	
ENG1	8	900	3,936	83.5	1
TURB_20F	20	950	33,000	112	2.5

Each source was modeled separately at a unitized emission rate of one pound per hour. This approach determined a unitized GLCmax for each source. The AQA predicted generic concentrations for 1-hour, 24-hour, and annual averaging periods. A NO_X to NO_2 conversion factor of 0.5 was used to predict NO_2 concentrations. This conversion factor of 0.5 is based on previously reviewed in-stack ratios of NO_X to NO_2 for engines and turbines, and is further supported by the EPA's March 1, 2011 guidance memo, which states, "Although well-documented data on in-stack NO_2/NO_X ratios is still limited for many source categories, we also feel that it would be appropriate in the absence of such source-specific in-stack data to adopt a default in-stack ratio of 0.5 as being adequately conservative in most cases and a better alternative to use than the Tier 1 full conversion." The GLCmax occurred near the stack for the scenarios modeled, so no appreciable conversion of NO_X to NO_2 is expected to occur in the short time it takes for the emissions to move from the stack to the location of the GLCmax. Therefore, the conversion factor of 0.5, which represents the higher end for both engines and turbines (in-stack ratios of 0.1 to 0.5 have been reported) was used to predict NO_2 concentrations.

The Toxicology Division confirmed that fugitive emissions from combustion units fueled only by pipeline-quality natural gas did not require an ESL review. The components of pipeline-quality natural gas are generally simple asphyxiants or have a low degree of toxicity, and experience has shown that fugitive impacts would be well below any applicable ESLs. Fugitive hydrogen sulfide emissions associated with CHP units were evaluated using SCREEN3. The SCREEN3 model was run using both urban and rural dispersion coefficients, and model parameters of a release height of 3 feet, a stack diameter of 0.001 feet, an exit velocity of 0.001 feet per second, and an ambient temperature of 68 degrees Fahrenheit. The predicted concentrations meet the state standards for hydrogen sulfide.

In response to comments, the commission defined certain scenarios where multiple facilities would be allowed under the PBR. The first scenario is when the emission points of all units are located in close proximity (within 200 feet). In this situation, the collection of sources can be approximated as a single larger source for purposes of modeling and impacts analysis. A group of closely-spaced units will have approximately the same offsite impact as a larger single source. Therefore, as long as the total capacity of the group of units is below the applicable 8 MW or 15 MW cutoff, and the appropriate emission standards and control requirements are met, this scenario is protective.

Another scenario which is allowed under the final PBR is the situation where the emission points of two or more units are separated by a distance of at least 900 feet. At this distance, the average predicted concentrations from the reasonable worst-case modeling scenarios are approximately half of the maximum predicted concentrations. In this case, the sources are far enough apart as to reduce any combined impacts to meet applicable standards.

Final Regulatory Impact Analysis Determination

The commission reviewed the adopted rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225 and determined that the adopted rule does not meet the definition of a "major environmental rule." Texas Government Code, §2001.0225 states that a "major environmental rule" is, "a rule the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure and that may adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state." While the purpose of this rulemaking is to increase protection of the environment and reduce risk to human health, it is not expected that this rulemaking will adversely affect in a material way the economy, a sector of the economy, productivity, jobs, the environment, or the public health and safety of the state or a sector of the state. Therefore, no regulatory impact analysis is required.

Furthermore, even if the rulemaking constituted a major environmental rule, a regulatory impact analysis would not be required because the rulemaking does not meet any of the four applicability criteria for requiring a regulatory impact analysis for a major environmental rule. Texas Government Code, §2001.0225 applies only to a major environmental rule that: 1) exceeds a standard set by federal law, unless the rule is specifically required by state law; 2) exceeds an express requirement of state law, unless the rule is specifically required by federal law; 3) exceeds a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopts a rule solely under the general powers of the agency instead of under a specific state law. The rulemaking does not meet any of the four applicability criteria listed in Texas Government Code, §2001.0225 because: 1) the rulemaking is designed to meet, not exceed the relevant standard set by federal law; 2) parts of the rulemaking are directly required by state law; 3) no contract or delegation agreement covers the topic that is the subject of this rulemaking; and 4) the rulemaking is authorized by specific sections of THSC, Chapter 382 (also known as the Texas Clean Air Act), cited in the Statutory Authority section of this preamble.

The specific intent of the rulemaking is to establish a PBR authorization and requirements for registering a stationary natural gas engine or turbine used in a CHP

system and to establish limits for air contaminants released by such engines. The commission is required to create such an authorization pursuant to THSC, §382.051865, added by HB 3268, 82nd Legislature, 2011.

The commission invited public comment regarding the draft regulatory impact analysis determination during the public comment period. The commission did not receive any comments on the draft regulatory impact analysis determination.

Takings Impact Assessment

The commission completed a takings impact assessment for this rulemaking action under Texas Government Code, §2007.043. The primary purpose of the rulemaking is to establish a PBR authorization and requirements for registering a stationary natural gas engine or turbine used in a CHP system and to establish limits for air contaminants released by such engines. The creation of a new PBR authorization for new stationary natural gas engines or turbines used in a CHP system does not affect private property in a manner that restricts or limits an owner's right to the property that would otherwise exist in the absence of a governmental action. This rulemaking will not revoke the authorizations of previously authorized facilities. The new PBR requirements would only apply to new or modified facilities. Consequently, this rulemaking action does not meet the definition of a takings under Texas Government Code, §2007.002(5).

Consistency with the Coastal Management Program

The commission determined that this rulemaking action relates to an action or actions subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act of 1991, as amended (Texas Natural Resources Code, §§33.201 *et seq*.), and commission rules in Chapter 281, Applications Processing, Subchapter B. As required by §281.45(a)(3) and 31 TAC §505.11(b)(2), relating to Actions and Rules Subject to the Coastal Management Program, commission rules governing air pollutant emissions must be consistent with the applicable goals and policies of the CMP. The commission reviewed this action for consistency with the CMP goals and policies in accordance with the rules of the Coastal Coordination Council and determined that the action is consistent with the applicable CMP goals and policies.

The CMP goal applicable to this rulemaking action is the goal to protect, preserve, and enhance the diversity, quality, quantity, functions, and values of coastal natural resource areas (31 TAC §501.12(l)). The adopted PBR will benefit the environment by ensuring that natural gas CHP units covered by the PBR will meet appropriate emission limitations that protect human health and air quality, while encouraging energy efficiency. The CMP policy applicable to this rulemaking action is the policy that commission rules comply with federal regulations in 40 CFR to protect and enhance air quality in the coastal areas (31 TAC §501.32). Therefore, in accordance with 31 TAC §505.22(e), the commission affirms that this rulemaking action is consistent with CMP

goals and policies.

The commission invited public comment regarding consistency of the rules with the CMP during the public comment period. The commission did not receive any comments on the consistency of the rules with the CMP.

Effect on Sites Subject to the Federal Operating Permits Program

Chapter 106, Subchapter A is an applicable requirement under 30 TAC Chapter 122, Federal Operating Permits Program. Owners or operators subject to the federal operating permit program who elect to use this PBR as authorization must, consistent with the revision process in Chapter 122, revise their operating permit to include the new Chapter 106 requirements upon the effective date of the adopted rulemaking.

Public Comment

The commission held a public hearing on April 3, 2012, at the commission's central office located at 12100 Park 35 Circle. The comment period closed on April 9, 2012. The commission received comments from the American Council for an Energy-Efficient Economy (ACEEE), General Electric (GE), Siemens Energy, Inc. (Siemens), Solar Turbines, Inc. (Solar), Stewart & Stevenson (S&S), Texas Combined Heat and Power Initiative (TXCHPI), Tognum America (TA), United States Clean Heat and Power Association (USCHPA), Universal Energy (UE), and an individual. All commenters

suggested changes to the proposed rule.

Response to Comments

General Comments

ACEEE, Solar, TXCHPI, and USCHPA generally indicated support for the proposed PBR for CHP facilities, although these commenters also recommended various changes in order to recognize common industry practices, widen the availability of the PBR, and improve the usability of the PBR, as discussed elsewhere in this response to comments.

The commission appreciates the support.

ACEEE, TXCHPA, USCHPA, and an individual provided general background information about the CHP industry, relating to the opportunities for growth in the CHP sector, the need for more power generating capacity in Texas, and the advantages of CHP in terms of reduced grid losses, environmental impact, and water consumption relative to other types of power generating systems and technologies.

The commission acknowledges the benefits and advantages of CHP as a means of providing efficient, reliable, and clean energy. The commission also acknowledges the importance of water conservation in the face of increasing water needs, and the current drought. However, as these

comments relate to the industry in general, and do not directly relate to the terms and conditions of the proposed rule, the TCEQ has not changed the rule in response to these comments, except as noted elsewhere in this response to comments.

Size of Units Eligible for the PBR

ACEEE, GE, Siemens, Solar, S&S, TXCHPI, USCHPA, UE, and an individual supported increasing the size of the CHP unit(s) that would be allowed under the PBR. ACEEE, TXCHPI, and USCHPA cited the 2008 Summit Blue report to the Public Utility Commission titled, "Combined Heat and Power in Texas: Status, Potential, and Policies to Foster Investment," which estimated that of the 13,400 MW of economic CHP opportunities identified in the report, 44% would come from installed systems ranging from 1 to 10 MW, and 50% was expected to be from systems larger than 10 MW. This suggests that approximately half of the remaining CHP potential in Texas will be met by systems larger than 10 MW. S&S commented that the proposed PBR would better serve the state if it were to allow units up to 15 or 20 MW in size. S&S stated that the proposed 5 MW limit would make some of the best candidates for CHP unable to apply for the PBR. UE recommended that the PBR allow CHP installations larger than 5 MW and stated that most industrial and institutional facilities have heating demands that coincide with power units that generate up to 20 MW. An individual commented that additional capacity was needed so that units in the small and medium size range (5 to 10

MW) could use the PBR, as it was still difficult for units in that capacity range to use the existing standard permit for EGUs. TXCHPI submitted information on a variety of prime movers and CHP systems to support the use of larger units under the PBR.

ACEEE and TXCHPI recommended adding levels or tiers to the PBR so that larger systems can use the PBR for authorization as an alternative to the existing EGU standard permit or a case-by-case air permit. TXCHPI requested that TCEQ examine a range of prime movers and site conditions in order to determine the appropriate maximum MW threshold for CHP systems under the PBR. TXCHPI noted that the implementing legislation did not include a size cap on the CHP units to be authorized under a PBR or standard permit. ACEEE and TXCHPI suggested the PBR should accommodate systems up to the point to where federal permitting requirements would prevent the use of a PBR. GE commented that that there should be no output cap on the PBR, as long as the units fall under federal annual emissions requirements. TXCHPI, USCHPA, and an individual commented that actual stack heights and stack parameters of typical CHP installations generally would result in better dispersion characteristics than the stack parameters used in TCEQ's proposal modeling of these units, and if more realistic stack parameters were used, it might be possible to increase the size of the units allowed under the PBR. Siemens suggested that units larger than 5 MW might still have an insignificant impact, depending on stack conditions, and suggested that TCEQ consider more flexible language allowing for larger units. Solar commented that if

current deadlines do not allow for the degree of analysis needed to address larger systems, perhaps a "round 2" could expand the PBR to include units larger than 5 MW in the near future.

The commission agrees that there is likely to be significant demand for a streamlined method to authorize CHP units larger than 5 MW in capacity. In response to these comments, the commission has increased the size of CHP units which may be authorized under the PBR. After additional review of modeling data, the commission found that the proposed size limit of 5 MW could be increased to 8 MW while still maintaining protection of human health and air quality standards. The commission has also added a tier for units or groups of units between 8 MW and 15 MW, although this tier requires more stringent emission standards and control requirements to ensure compliance with applicable NAAQS. The additional control requirement of an oxidation catalyst for units between 8 and 15 MW is necessary to address emissions of condensable $PM_{2.5}$ which might otherwise exceed the applicable NAAQS for $PM_{2.5}$. The more stringent NO_X standard is necessary to ensure the larger units maintain compliance with the NAAQS for NO_2. Finally, the commission has added language to the PBR so that multiple units or groups of units, with a capacity of up to 15 MW, could be authorized under the PBR, in situations where there is sufficient distance

between the units or groups of units. However, all facilities must still meet the overall emission limitations of §106.4, which could become a limiting factor for multiple larger units or groups of units.

Fuels Allowed under the PBR

GE, Solar, TXCHPI, UE, and USCHPA requested that the PBR provide more flexibility with respect to the types of allowed fuels. GE stated that their gas engines and gas turbines are capable of operating on a variety of gaseous and liquid fuels producing low emissions, and recommended extending the PBR to include other fuels in addition to pipeline quality natural gas. Solar and TXCHPI stated that while current technology may not allow liquid fuel or non-natural gas gaseous fuels to meet the emission standard without add-on controls, a fuel neutral PBR could allow for any future combustion technology breakthroughs in non-natural gas fuels to be eligible for the PBR. UE stated that it would be logical to ensure the PBR provides the latitude to take advantage of cleaner alternative fuels. UE also stated that natural gas turbines and reciprocating gas engines are versatile and have predesigned options to accommodate other fuels. UE recommended that the PBR allow some amount of operating time on emergency fuels, or possible alternative fuels that are needed as a backup supply to ensure reliability of the CHP unit. Universal Energy identified propane as a viable backup fuel for one installation. USCHPA and TXCHPI stated that the PBR should be limited to units primarily using natural gas, but suggested that the commission provide some leeway to

accommodate systems which may operate for a limited number of hours on an alternate fuel. USCHPA and TXCHPI stated that many engine and combustion turbine prime movers have the capability to operate on both natural gas and liquid fuels. USCHPA and TXCHPI stated that this capability is critical for facilities such as hospitals, data centers, and other applications where energy security is paramount. USCHPA and TXCHPI stated that because the use of a secondary fuel is envisioned only in emergency situations, emissions resulting from operation on a secondary fuel are expected to be very limited. USCHPA and TXCHPI recommended a limit of no more than 300 hours of operation on the secondary fuel, consistent with similar time limits established in the standard permit for distributed electrical generation units. TXCHPI stated that propane could be an appropriate backup fuel in certain applications. TXCHPI also suggested that the TCEQ should consider allowing plant fuel gases as an allowed fuel type under the PBR.

In response to these comments, the commission has added language to allow for the use of propane, LPG, gasoline, diesel, or fuel oil as an emergency fuel, for a period of up to 720 hours in any 365-day period. These fuels are only allowed in emergency situations when the normal fuel (pipeline quality natural gas) is not available.

With respect to the use of liquid fuels under non-emergency conditions,

although progress has been made in reducing emissions from units fired with liquid fuels, the emission characteristics of liquid fuel units are different enough from natural gas units so that they would be difficult to address in this PBR without considerable additional evaluation and appropriate control measures to ensure protection of human health and compliance with applicable air quality standards. As to other possible fuels, such as plant fuel gas, refinery gas, and other waste gases and off-gases, the uncertain and variable composition of those fuels makes it difficult to anticipate and address all the possible impacts of those fuels without closer review.

Solar commented on a statement in the proposal preamble which stated that "The only turbines capable of firing liquid in addition to gaseous fuel represent older technology (diffusion flame combustors) that is unlikely to meet the emission standards of the proposed PBR." Solar stated that this statement may be true for some manufacturers, but is not true across the board. Solar stated that their dual fuel *SoLoNO*$_X$ (or dry low NO_X) technology has been used on turbines since 1995. Solar stated that while liquid fuel fired turbines are unlikely to meet the emission standards of the proposed PBR, the above referenced sentence should be removed or rewritten.

The commission acknowledges that some dual fuel turbines may be able to

approach or meet the NO_X and CO emission standards of the PBR. If Solar or other manufacturers offer equipment which can meet the emission standards while operating on liquid fuel, the commission apologizes for the misstatement. However, while operating on liquid fuels, even if the NO_X and CO emissions are relatively low, the particulate emissions are likely to be substantially higher than those from a natural gas-fired unit, such that further evaluation would be needed to address non-emergency operation of liquid fueled units under the PBR.

Supplemental Firing of Heat Recovery Steam Generators (HRSG)

TXCHPI, UE, and USCHPA commented that that the PBR should allow for supplemental HRSG firing. TXCHPI, UE, and USCHPA commented that supplemental firing is a common industry practice for utility-scale generating plants and CHP units, and is a highly efficient power augmentation method. USCHPA stated that CHP systems that are larger than 5 MW typically include a combustion turbine with a heat recovery system. The heat recovered is typically in the form of steam, but it can also be another heat transfer or process fluid. USCHPA stated that the combustion turbine exhaust temperature is often increased using supplemental fuel fired in a duct burner to increase the thermal energy output through heat recovery.

The commission believes that industrial systems using supplemental firing

downstream of the prime mover were not the intended target of the legislation or this PBR. The commission intends for the PBR to reward the recovery of energy that would normally be wasted. Recovering energy from hot exhaust produces no additional pollution and could be replaced by burning more fuel in another unit such as a boiler if no recovery occurred in the CHP unit. Adding an additional source of pollution to the CHP unit, which supplemental firing would entail, would not meet the intent of the PBR. The commission has not changed the rule in response to these comments.

USCHPA and TXCHPI suggested that TCEQ allow the use of industrial by-product gases, waste gases, off-spec gases, and flare gases in supplemental HRSG firing applications. These gases can be used to augment steam production for thermal applications and/or electrical production, if a steam turbine generator is integrated in the project.

As discussed previously, the commission has determined that the PBR will not include systems which use supplemental firing downstream of the EGU. In addition, as previously discussed, the variability in the composition of these types of nonstandard fuels makes it difficult to address such fuels in a PBR.

Registration and Exemptions for CHP Units under 20 kW

ACEEE, TCXHPI, and USCHPA supported the exemption for units under 20 kW, and stated that the proposed 20 kW threshold level for the exemption was appropriate. However, each of these commenters also recommended that this exemption should not distinguish between units in a residential application and those in industrial or commercial applications, and that the non-residential CHP units should be exempt from registration as well as residential units. ACEEE, TXCHPI, and USCHPA stated that this approach would be consistent with the language of HB 3268, which indicates that the TCEQ should adopt a rule that is independent of end use or application bias.

The commission believes that a one-time registration requirement is reasonable for non-residential (commercial and industrial) CHP units which will be claiming this PBR. The registration requirement will allow the commission to gather information on the location and nature of CHP systems using the PBR, which may be helpful in determining if future changes are needed. Regardless of whether a sub-20 kW unit is in residential, commercial, or industrial service, it is exempt from the emission standards and testing and monitoring requirements of the PBR. Aside from the registration requirement, there is no practical difference in the technical requirements for units under 20 kW, regardless of the

location or type of service. The commission has not changed the rule in response to this comment.

Emission Standards of the PBR

Siemens noted that the proposed PBR contains an output based emission standard of 1.0 lb/MWh for NO_X, and Siemens indicated support for this output-based approach. TA also expressed support for an output-based approach to the standards. GE stated that modern gas engines and gas turbines frequently achieve less than 1 lb NO_X/MWh and less than 9 lb CO/MWh without using catalysts.

The commission agrees with the comment that the emission limitations are appropriate and achievable. The commission has not changed the rule in response to this comment.

TA indicated that the low emission, full CHP version of certain TA products achieves the emission levels outlined in the PBR. However, TA stated that other products in their product line would require substantial reengineering to meet the PBR requirements, and the cost of such re-engineering compared to the sales volume opportunity in Texas may not be practical. TA stated that the preferred emission level would be 3.1 lb NO_X/MWh, as this allows engine operation at optimal efficiency, fuel consumption and spark plug life. TA stated that at the 1.8 lb NO_X/MWh level, fuel consumption increases for the

same electrical output, which results in higher emissions of greenhouse gases. TA stated that NOx emissions below 1.8 lb NO_X/MWh are currently not attainable with lean-burn engines without using a Selective Catalytic Reduction (SCR); only rich-burn engines with three-way catalysts can attain emission levels below this level.

Other commenters have been generally supportive of the proposed emission standards, or have not expressed concern about their stringency. The commission has reviewed information which indicates that some manufacturers offer lean burn engines which could meet the PBR's emission standards without additional control. The commission believes that the emission standards are reasonable and has not changed the rule in response to this comment. The PBR is not intended to cover all possible equipment configurations and variations. Owners or operators of facilities which are unable to meet the PBR requirements may apply for a case-by-case permit.

Siemens and USCHPA commented that for some prime movers, some pollutant concentrations may be lower at the outlet or exhaust than in the ambient air inducted into the unit, such that the environmental impact should be based on the difference between inlet and outlet conditions.

The commission finds it commendable that some engines or turbines may produce such low emission rates that the outlet concentration of pollutants such as CO or NO_X could be less than or equal to the inlet concentration. However, these situations are not typical, and measuring the pollutant rate or concentration on a net basis is not a typical practice for air permitting or other air regulatory purposes. Regardless of the inlet concentrations of pollutants, the overall impact of the operation of the unit on human health and on air quality standards is still determined by the emission rates from the exhaust of the unit. The commission has not changed the rule in response to this comment.

Number of CHP Units Allowed under the PBR

ACEEE, GE, Solar, S&S, TXCHPA, UE, and USCHPA commented that the PBR should allow for more than one CHP unit at a site. The commenters stated that that some reasons why multiple prime movers were necessary or beneficial included: the need to allow for phased implementation of some projects; the need to follow a site's variable thermal load; greater efficiencies from multiple smaller units compared to a single unit running at part load; and the need for redundancy and reliability, which can be better met with multiple smaller units.

The commission acknowledges that in some CHP applications, it may be

desirable or even necessary to have the ability to operate multiple individual units. However, it is difficult to address multiple units within the context of a standardized, generic authorization such as a PBR because there are such a wide range of possibilities as to how the sources may be positioned in relation to each other and in relation to the surrounding area. This is especially the case when considering CHP systems, which may be installed on or near buildings in an urban environment, in close proximity to public places. After a review of modeling results, the commission has determined that allowing multiple units would be protective, for certain specific scenarios.

First, the PBR will not limit the number or location of units with a capacity of less than 20 kW, as the impacts from such small units are not expected to be significant, even if a number of them are present at a site.

The second scenario is if the emission points for all CHP units authorized under the PBR fall within a circular area with a radius that does not exceed 200 feet. This approach is possible because a number of individual sources in close proximity can be approximated as one source in a modeling demonstration, essentially treating the multiple sources as one unit. This scenario may allow for a number of microturbines or other units which are

in close proximity. In order to determine the applicable emission standard and control requirements, the capacity of all units within the 200 feet radius must be totaled. For example, if the total capacity of all units within the defined radius was 7 MW, that would fall under §106.513(d)(2), covering combinations of units of 8 MW or less. If the total capacity of all units within the 200-foot radius was 9 MW, those units would be subject to §106.513(d)(3).

The third scenario would cover multiple CHP units, or multiple groups of units, if the emission points from those CHP units (or groups) are separated by a distance of least 900 feet. This scenario would allow multiple units that are far enough apart to ensure that any combined impacts from the units would not result in a risk to human health or the environment. The commission selected 900 feet as the distance criteria because at this distance, the average predicted concentrations from the reasonable worst-case modeling scenarios are approximately half of the maximum predicted concentrations. The emission standards and requirements for this scenario are covered under §106.513(d)(4).

If multiple units are to be authorized under any of these scenarios, the applicable emission standard for the units would be determined by the total

combined capacity of all units under the PBR. Note that all facilities are subject to the requirements of §106.4, which could become a limiting factor if multiple units are present.

Other Comments

TXCHPI stated that language in the PBR is needed to better address the use of microturbines. TXCHPI requested that TCEQ examine a range of prime movers and site conditions related to microturbines so that a wide range of these efficient systems can use the PBR.

The commission is not entirely certain what aspect of the PBR this comment is referring to. The PBR has been developed with appropriate consideration for a range of prime movers, from microturbines up to units of several MW in capacity. The emission standards, exemption levels, and other requirements of the PBR are appropriately constructed so that microturbines should be able to use the PBR for authorization without significant difficulty. Because microturbines are more likely to be used in groups in relatively close proximity, the commission has added language which may allow for the use of multiple microturbines at a site, if certain distance restrictions are met.

TXCHPI commented that microturbines are typically located in a fairly compact area, and should be treated as one unit or package for purposes of the PBR, instead of having to manifold multiple units into a common stack.

The commission has added language which allows for the use of multiple turbines (including microturbines) or engines at a site, if the emission points of the units are located within a circular area having a radius of 200 feet. In many cases, this would eliminate the need to manifold multiple units into a common stack.

An individual commented that the current air permitting system is a hindrance to CHP development. The individual stated that the case-by-case air permit process is especially burdensome for small engines or combustion turbines commonly used at sites with relatively small thermal requirements. The individual also stated that the standard permit for electric generating units requires small units to meet limits comparable to large natural gas combined cycle power plants, which are able to use commercially available low NO_X combustion systems supplemented with SCR. The individual stated that comparable low NO_X combustion systems for small units cannot achieve the same low emission levels, and SCR systems are not practical for smaller units. The individual stated that for these reasons, it is critically important to have a permitting mechanism that will encourage development of small to medium sized CHP.

The commission recognizes that the full case-by-case permit system can be burdensome for small facilities, and over time has developed streamlined permitting options such as standard permits and PBRs where possible to provide an appropriate alternative for smaller facilities. While the East Texas NO_X emission limits of the standard permit for EGUs are stringent, they were intended to require BACT, protect the SIP, and to reflect the expectation that emission performance of small units would improve as new technology became available. Nevertheless, the commission believes that the CHP PBR should substantially address the concerns expressed by the commenter, by providing a streamlined alternative to a case-by-case permit or the standard permit for EGUs.

Siemens provided information on the CO_2 emission footprint for a range of gas turbine sizes and efficiencies.

As TCEQ does not authorize or regulate emissions of CO_2, no changes to the rule were made in response to this information.

Solar, TXCHPI, and USCHPA noted that the fiscal portion of the preamble language stated that the monitoring and testing cost for CHP units authorized by the proposed

PBR are expected to be about the same as costs for the standard permit. Solar, TXCHPI, and USCHPA stated that CHP facilities are usually base-loaded and operate continuously, except for short scheduled maintenance periods. Solar, TXCHPI and USCHPA stated that if performance testing is required every 16,000 hours of operation, then testing would occur at least two additional times in the first five years of operation. Solar, TXCHPI, and USCHPA stated that these retesting costs do not appear to have been included in the PBR's cost impact assessment.

The commenters are correct that the cost estimates discussed in the preamble did not include the long-term costs of the recertification testing that is required every 16,000 hours of operation. The commission anticipates that the retesting costs would be approximately $6,000 - $10,000 for each 16,000-hour period. The commission regrets the oversight. No change has been made to the rule in response to this comment.

TXCHPI and USCHPA stated that the stack height for CHP units is usually a minimum of 50 feet above grade. TXCHPI and USCHPA also stated that most heat recovery systems have a high profile, so the outlet breeching to the stack is at least 20 to 30 feet above grade, and larger units will be taller. TXCHPI and USCHPA stated that stack height is added above the breeching to allow a fully developed parallel flow profile for

emission testing. USCHPA also stated the typical stack velocity is 50 to 75 fps.

Although one would intuitively expect a higher stack to result in improved dispersion characteristics and a reduced ground level impact, the commission found that the limiting factor in the modeling was the presence of downwash caused by buildings and not the height of the stack. Modeling taller release heights did not result in substantial change to the protectiveness review. Reasonable worst-case stack parameters were derived from an industry review of sources and based on the review, engine and turbine exhaust stacks were modeled with exit velocities of 83 and 112 fps, respectively. However, as discussed elsewhere, the commission was able to increase the size of the units (or groups of units) allowed under the PBR from 5 MW to 8 MW, and up to 15 MW if additional controls are applied. All facilities must still meet the overall limitations of §106.4, which could become a limiting factor for multiple larger units or groups of units.

TXCHPI commented that the definition of CHP unit as proposed was too limiting, and suggested alternate language. USCHPA supported TXCHPI's suggestion to revise the definition of CHP. TXCHPI's alternate language would allow for multiple EGUs, would remove language which specified that the recovered heat energy must be used for purposes other than the generation of more electricity, and would remove language that

excluded facilities downstream of the EGU which generate additional electricity.

The intent of this definition was to state a general understanding of a basic CHP unit to show the purpose of the PBR. Although the commission is not changing the definition of CHP unit in response to this comment, the commission has revised other portions of the PBR to allow for multiple units under certain circumstances. If the definition itself were to allow for multiple EGUs, this could conflict with or undermine other conditions in the PBR which are intended to ensure that situations involving multiple EGUs are protective. As long as each unit is within a 200-foot radius circle as discussed elsewhere in this response to comments, the group of units would be allowed under the PBR. Units that do not have a stack within the 200-foot radius circle will not be considered part of the group even if the heat recovery systems are connected.

With respect to allowing electric generation after the EGU to count as part of the CHP unit; this would broaden the applicability of the PBR to electric generating facilities. There would be no heat recovery component other than to make more electricity. This would be not be consistent with the intended purpose of the PBR. The commission has not changed this aspect of the definition.

As explained in the preamble, additional electric generation after the EGU is not part of the CHP unit because that generation would not constitute a facility by itself. If a CHP unit can meet the 20% recovery requirement, additional generation such as the use of a Stirling engine or a steam turbine would be allowed. However, none of the power created by that generator will count towards showing compliance with the requirement of the PBR.

TXCHPI commented that with respect to CHP projects larger than 5 MW, the actual variability among projects is less than might be anticipated. CHP projects of this size are most often implemented in large facilities or in campus environments, most of which will include a central utility plant (CUP) to house boilers, chillers, and related equipment. The most likely location for CHP equipment, whether it is a retrofit or new construction, would be within the CUP. TXCHPI explained that because the CUP may be perceived as eye sore and potential source of noise pollution, it is often built somewhat remote from the primary pedestrian areas in a stand-alone building. However, the CUP must be reasonably proximate to the steam and chill water loads. Because natural gas-fired boilers are a component in most CUPs, NO_X emission permits may already be required for existing facilities. As a result, modeling studies with specific assumptions regarding location and proximity of the CUP to other structures may already be available.

The commission acknowledges for some or many installations of larger CHP systems, the CHP equipment may be located in a CUP some distance away from heavily trafficked public areas. However, this general knowledge is still not specific enough to construct the detailed scenarios and impact studies to ensure that large units under the PBR would maintain compliance with applicable standards and ensure protection of human health. As previously discussed, the commission has increased the size of the units which would be allowed under the PBR; however, the rule was not changed in response to this particular comment.

TA commented that they offer a CHP module which recovers heat from the engine cooling water, mixture intercooler and lube oil cooler. TA stated that under their current understanding of the PBR, this version would not qualify as a CHP system with minimum 20% exhaust heat recovery, since the only heat recovery is from the jacket water. TA requested that the PBR be revised to not just include exhaust heat recovery, but total heat recovery. TA stated that this would allow for all the benefits of recovering energy from the unit and not just exhaust heat.

The commission agrees that in some cases, waste heat may be recovered in other ways, which would not be accounted for if the PBR only considered

the heat recovered from the exhaust. The commission has revised the PBR to remove specific references to exhaust heat so that other types of heat recovery may be included when evaluating the 20% heat recovery criteria and the total credit for heat recovered.

TA requested clarification as to the derivation of the 1 MWh per 3.4 MMBTU factor used in the calculation to determine the emission level of exhaust heat recovery units. TA stated that a factor on the order of 1 MWh per 2.0 MMBTU would allow for all modules to be compliant with the standards and provide a slight margin between the module emission level and the proposed standard.

The credit of 1 MWh per 3.4 MM BTU provided in the PBR is a direct conversion. One MWh is an equivalent amount of energy to 3.41 MM BTU. The commission does not agree that a factor of 1 MWh per 2 MM BTU would be appropriate, as it would provide an amount of credit that substantially exceeds the amount of energy recovered. No change to this rule has been made in response to this comment.

SUBCHAPTER W: TURBINES AND ENGINES

§106.513

Statutory Authority

The new rule is adopted under Texas Water Code, §5.103, concerning Rules, and §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the Texas Water Code; and under Texas Health and Safety Code (THSC), §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purposes of the Texas Clean Air Act. The new rule is also adopted under THSC, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.051, concerning Permitting Authority of Commission; Rules, which authorizes the commission to issue a permit by rule for types of facilities that will not significantly contribute air contaminants to the atmosphere; §382.05196, concerning Permits by Rule, which authorizes the commission to adopt permits by rule for certain types of facilities; §382.057, concerning Exemption, which authorizes exemptions from permitting; and §382.051865, which requires the commission to issue a standard permit

or permit by rule for stationary natural gas engines used in a combined heating and power system.

The adopted new rule implements THSC, §§382.002, 382.011, 382.012, 382.017, 382.051, 382.051865, 382.05196, and 382.057.

§106.513. Natural Gas-Fired Combined Heat and Power Units.

(a) Applicability.

(1) This section applies to combined heat and power (CHP) units that are powered by pipeline-quality natural gas-fired engines, including turbines. This section also authorizes any fugitive components associated with a CHP unit authorized by this section.

(2) This section does not relieve the owner or operator from complying with any other applicable provision of the Texas Health and Safety Code, Texas Water Code, rules of the Texas Commission on Environmental Quality (TCEQ), or any additional local, state, or federal laws or regulations. Emissions that exceed the limits in this section are not authorized and are violations.

(b) Definitions.

(1) Combined heat and power (CHP) unit--A collection of facilities and other equipment that generally consists of an electric generating unit (EGU) and a means of extracting energy from the EGU for useful purposes other than electricity generation, such as heating or cooling. A CHP unit does not include facilities for generating additional electricity after the EGU. Equipment that is not a source of emissions itself but also extracts energy from the exhaust flow to create electricity is not a facility and may be used in addition to a CHP unit authorized by this section.

(2) Pipeline-quality natural gas--A naturally occurring fluid mixture of hydrocarbons (composed predominantly of methane, with lesser amounts of ethane, propane, nitrogen, carbon dioxide, and trace amounts of hydrogen sulfide) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and that is provided by a supplier through a pipeline. Pipeline-quality natural gas must either be composed of at least 70% methane by volume, or have a gross calorific value between 950 and 1,100 British thermal units (BTU) per standard cubic foot. Sour gas as defined in §101.1 of this title (relating to Definitions) is not pipeline-quality natural gas for purposes of this section.

(c) General Requirements.

(1) A CHP unit must be registered with the commission using the appropriate PI-7 form or an approved electronic registration method before start of construction. A CHP unit at a residential location that generates less than 20 kilowatts(kW) of electricity does not require registration and does not have to meet any other requirements of this section except subsection (a) of this section and paragraph (2) of this subsection.

(2) For a CHP unit to be eligible for authorization under this section, the heat recovered must equal at least 20% of the total heat energy output of the CHP unit. This requirement must be met continuously based on any calendar week of operation except for no more than two weeks in a rolling 52-week period if operation of the EGU component is necessary due to lack of available electricity.

(3) No owner or operator of a CHP unit that is required to register under this section may begin construction and/or operation without first obtaining written approval from the executive director.

(4) Except for oxidation-reduction (three-way) catalysts on rich-burn engines, and oxidation catalyst controls as required by subsection (d)(3) or (4) of this

section, add-on controls may not be used to comply with the emission standards of this section.

(5) Any individual CHP unit, or any group of units meeting paragraph (7)(B) of this subsection, may not exceed 15 megawatts (MW) in capacity.

(6) Only one permit by rule (PBR) for Natural Gas-Fired CHP Units per this section may be registered at a site.

(7) No more than one CHP unit may be authorized at a site under this section, except as follows:

(A) Any units with a capacity of less than 20 kW are not limited in number, or restricted in location. Units with a capacity of less than 20 kW are not required to be considered when applying subparagraphs (B) or (C) of this paragraph.

(B) Multiple units may be authorized under this PBR if all stack emission points associated with the units are located within a circular area with a radius of 200 feet, and the total EGU capacity of the group is not greater than 15 MW.

(C) Multiple units may be authorized under this PBR if all stack emission points associated with the units are separated by a distance of at least 900 feet.

Multiple groups of units meeting the requirements of subparagraph (B) of this paragraph may be authorized if the groups' emission points are separated by a distance of at least 900 feet.

(8) Notwithstanding fuel restrictions elsewhere in this section, during an emergency, this PBR authorizes the use of propane, liquefied petroleum gas, gasoline, diesel, or fuel oil as an approved fuel for not more than 720 hours in any 365-day period. This PBR also authorizes brief use of these emergency fuels as needed for purposes of maintenance or testing, for not more than two hours in any seven-day period.

(d) Emission Standards and Control Requirements.

(1) Notwithstanding paragraphs (2), (3), or (4) of this subsection, a CHP unit with a capacity less than 20 kW is not subject to a nitrogen oxides (NO_X) or carbon monoxide (CO) emission standard, and is not subject to the requirement for an oxidation catalyst control device.

(2) A CHP unit or any combination of units with a total capacity greater than or equal to 20 kW, but less than or equal to 8 MW, must meet the following emission standards: 1.0 pound of NO_X per megawatt-hour (lb NO_X/MWh); and 9.0 lb CO/MWh.

(3) Except as provided in paragraph (4) of this subsection, a CHP unit or any combination of units with a total capacity greater than 8 MW must meet the following emission standards: 0.7 lb NO_X/MWh; and 9.0 lb CO/MWh. A CHP unit or units under this paragraph must also be equipped with an oxidation catalyst control device that maintains a minimum of 70% control of volatile organic compounds (VOC) in the CHP unit exhaust stream.

(4) Any combination of CHP units with a total capacity greater than 8 MW that are at least 900 feet apart from one another must meet the following emission standards and control requirements. For the purposes of this paragraph, any group of units under subsection (c)(7)(B) of this section is considered to be one unit when determining whether subparagraph (A) or (B) of this paragraph applies.

(A) CHP units with a capacity less than or equal to 8 MW: 1.0 pound of NO_X per megawatt-hour (lb NO_X/MWh); and 9.0 lb CO/MWh.

(B) CHP units with a capacity greater than 8 MW: 0.7 lb NO_X/MWh; and 9.0 lb CO/MWh. A CHP unit under this subparagraph must also be equipped with an oxidation catalyst control device that maintains a minimum of 70% control of VOC in the CHP unit exhaust stream.

(5) Compliance with the NO_X standards above may be achieved by taking credit for the heat recovered from the combustion unit. Credit will be at the rate of 1.0 MWh for each 3.4 million BTU of heat recovered. In order to claim this credit for CHP for units not sold and certified as an integrated package by the manufacturer, 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.

(e) Monitoring and Testing. CHP units authorized under this section with an electric generating capacity greater than or equal to 20 kW must meet the following requirements :

(1) Internal combustion engine-based CHP units (excluding turbines).

(A) The owner or operator shall initially analyze the emissions from the CHP unit using a portable analyzer no later than 180 calendar days after startup.

(B) After the initial testing specified by subparagraph (A) of this paragraph, the owner or operator shall conduct ongoing monitoring using a portable analyzer, once in the first half of each calendar year and once in the second half of each

calendar year, with at least two months between tests. When a CHP unit did not operate for more than 1,000 hours in that half of the year, this test is not required.

(C) The portable analyzer must be operated at minimum in accordance with the manufacturer's instructions. A copy of the manufacturer's instructions shall be made available upon request. The NO_X and CO emissions must be converted into units of lb/MWh.

(2) Internal combustion engine-based CHP units and turbines. If the CHP unit is not certified to meet the emission standards of subsection (d) of this section by the manufacturer according to a United States Environmental Protection Agency (EPA) testing protocol, the unit must be tested within 90 days of startup for NO_X and CO according to appropriate EPA reference methods, California Air Resources Board methods, or equivalent alternative testing methods approved by the executive director and in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual. Tests must consist of three runs with a minimum of 30 minutes for each run or longer if required by the reference method. All engine- and turbine-based CHP units designed to generate more than 375 kW must be retested by the above method after every 16,000 hours of operation, regardless of certification.

(3) All CHP units which are required by subsection (d)(3) or (4) of this section to have an oxidation catalyst control device shall be tested to verify compliance with the required 70% VOC control efficiency within 90 days of startup. In lieu of the above test, the 70% VOC control requirement shall be satisfied if the unit is tested for gaseous organic compounds and the reduction is at least 90%. The testing shall be conducted using EPA reference methods or equivalent alternative testing methods approved by the executive director and in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual. All units required to be equipped with an oxidation catalyst control device must also be retested after every 16,000 hours of operation.

(4) Except for rich-burn engines equipped with oxidation-reduction (three-way) catalysts, and units required to be equipped with an oxidation catalyst under subsection (d)(3) or (4) of this section, the uncontrolled source must demonstrate compliance with the emission standards in subsection (d) of this section.

(f) Recordkeeping. In addition to the minimum records required by §106.8 of this title (relating to Recordkeeping), the owner or operator must keep the following records:

(1) For the life of the CHP unit, the registration application and any additional representations made during the approval process to obtain the registration; and

(2) The owner or operator must keep the following records for at least two years and make them available to the TCEQ or any local pollution control program with jurisdiction upon request:

(A) A record of every one-week period of operation where the CHP unit did not comply with subsection (c)(2) of this section;

(B) All monitoring and testing data generated in compliance with subsection (e) of this section and in a format that shows the emission standards have been met;

(C) Records of CHP unit operation sufficient to demonstrate compliance with any applicable hour-based requirements of subsection (e) of this section;

(D) Records of maintenance described in subsection (g)(2) of this section; and (E) Records of the number of hours that any emergency fuel is used under

subsection (c)(8) of this section, and the reason why operating on an emergency fuel is necessary.

(g) Planned Maintenance, Startup, and Shutdown.

(1) This PBR authorizes all emissions from planned startup and shutdown activities associated with facilities that are authorized by this section.

(2) This PBR authorizes emissions from the following planned maintenance activities associated with facilities authorized by this section: routine maintenance including, but not limited to, filter changes, oxygen sensor replacements, overhauls, lubricant changes, spark plug changes, and emission control system maintenance.