The Texas Commission on Environmental Quality (TCEQ, agency, or commission) proposes new §106.513.

Background and Summary of the Factual Basis for the Proposed 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 proposes new §106.513, to authorize natural-gas fired CHP units as outlined by HB 3268 and THSC, §382.051865. As with all PBRs, this proposal 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.

Proposed §106.513(a)(1) establishes the applicability of this PBR to CHP units that generate no more than 5 megawatts (MW) of electricity and are powered by pipeline-quality natural gas. Engines and turbines meeting the applicable conditions may be authorized under this PBR. Industry data available to TCEQ suggests that a 5 MW capacity limit is sufficient to cover a wide range of CHP applications. Emissions from CHP units with a capacity greater than 5 MW were not evaluated as there was insufficient information to identify and evaluate possible facility configurations for these units. However, units with a capacity greater than 5 MW would be expected to meet the emissions standards of the air quality standard permit for EGUs (or a case-by-case permit) since previous TCEQ permitting experience has shown those larger units are usually permitted with add-on controls such as selective catalytic reduction. The only fuel type authorized under the proposed PBR is pipeline-quality natural gas. The PBR does not authorize fuel oil or any other fuel as a backup fuel to pipeline-quality natural

gas. The commission is not aware of units using other fuels (such as fuel oil) typically being capable of meeting the emission standards in the proposed PBR. 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. Natural gas-fired engines do not typically have the ability to readily switch from gas to liquid fuel. The only turbines capable of firing liquid fuel in addition to gaseous fuel represent older technology (diffusion flame combustors) that is unlikely to meet the emission standards of the proposed PBR.

Proposed §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.

Proposed §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 proposed 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.

Proposed §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 proposed 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. A clarifying statement has been added to the proposed definition to ensure that sour gas as defined in 30 TAC §101.1, Definitions, may not be used as a fuel under this PBR.

Proposed §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 §106.513(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.

Proposed §106.513(c)(2) establishes a minimum required level of heat recovery for units authorized under this section. As proposed, 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 of the exhaust gases 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. It is necessary to specify a minimum required level of heat recovery to ensure that this PBR is only used for projects that have a significant CHP component.

Proposed §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. Written approval is justified 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.

Proposed §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. 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)(3) to comply with the emission standards without regard to add-on controls. 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. If the use of add-on controls would be

necessary to meet an applicable emission standard of this PBR, the unit must be authorized using the standard permit for EGUs or a case-by-case new source review permit, applying BACT.

Proposed §106.513(c)(5) restricts the use of this PBR to one CHP unit at a given site. This restriction is necessary to prevent cumulative impacts from multiple sources and ensure that emissions from CHP facilities authorized under this PBR at a site do not trigger federal emission significance levels.

Proposed §106.513(d) establishes emission standards for CHP units authorized under this section. These emission standards are based on the maximum electrical production capacity of the unit. Units producing less than 20 kW are not subject to an emission standard under §106.513, but remain subject to the general emission limitations contained in §106.4.

Proposed §106.513(d)(2) establishes a nitrogen oxide (NO_X) emission standard of 1.0 pound (lb)/megawatt-hour (MWh) for units with a capacity greater than or equal to 20 kW. Additionally, all CHP units with a capacity greater than or equal to 20 kW are subject to a carbon monoxide (CO) emission standard of 9.0 lb/MWh.

Proposed §106.513(d)(3) establishes that for each 3.4 million British Thermal Units

(MM Btu) of heat recovered, a credit of 1 MW is provided. The CHP credit in §106.513(d)(3) allows for the energy recovered by the CHP system to be considered when determining compliance with the emission standards. The purpose of this PBR is to allow CHP units to take into account the benefit of recovering energy from exhaust 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.

Proposed §106.513(e) contains monitoring and testing requirements that are necessary to ensure that the authorized facility 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. Proposed §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.

Proposed §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 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 are required to be retested after every 16,000 hours of operation, regardless of certification status.

Proposed §106.513(e)(3) specifies that, except for rich-burn engines equipped with oxidation-reduction (three-way) catalysts, the uncontrolled source must be used in demonstrating compliance with the emission standards in §106.513(d).

Proposed §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 proposed §106.513(e)(1)(B), or the 16,000 hour retest requirement in proposed §106.513(e)(2). Owners or operators are also required to maintain records of planned maintenance activities authorized under proposed §106.513(g)(2).

Proposed §106.513(g) authorizes emissions from planned maintenance, startup, and shutdown activities that are typical for engines and turbines. Under proposed §106.513(g)(1), emissions resulting from startup and shutdown operations of CHP units are authorized under this PBR. Proposed §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. Other maintenance activities that are routine for engines and turbines in a CHP application are also authorized.

In developing this PBR, all expected air emissions from CHP units of 5 MW or less were evaluated for compliance with applicable state and federal air quality standards and state guideline effects screening levels (ESLs). The commission determined that applicable national ambient air quality standards (NAAQS), state standards for sulfur dioxide (SO_2) and hydrogen sulfide, and state ESLs would be met.

The 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) were estimated 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 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 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 5 MW or less. 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 (higher predicted concentrations) 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.

The AQA used a polar receptor grid with 36 radials spaced every 10 degrees from true north. Receptors were located on each radial at initial distances of 100, 150, and 200 feet, and then incrementally every 100 feet out to 3,000 feet, and then incrementally every 500 feet out to 5,500 feet from the sources. Therefore, plume meander was not considered and the model predicted maximum plume centerline concentrations.

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 minute)	Stack Exit Velocity (feet per second)	Diameter (feet)
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 maximum predicted ground-level concentration (GLCmax) for each source. The AQA predicted generic concentrations for 1-hour, 24-hour, and annual averaging periods. A NO_X to nitrogen dioxide (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 1 meter (m) release height, a stack

diameter of 0.0003 m, an exit velocity of zero meter per second (m/sec), and an ambient temperature of 293 Kelvin. The predicted concentrations meet the state standards for hydrogen sulfide.

Fiscal Note: Costs to State and Local Government

Nina Chamness, Analyst, Strategic Planning and Assessment, has determined that, for the first five-year period the proposed rule is in effect, no significant fiscal implications are anticipated for the agency or other units of state or local government as a result of administration or enforcement of the proposed rule.

The proposed rule would implement the provisions of HB 3268 by establishing a new PBR to authorize stationary natural gas engines and turbines used as part of a CHP system. The proposed PBR would provide a more practical and less expensive authorization process for these types of engines and turbines. The proposed PBR would: apply to CHP units that generate no more than 5 MW of electricity; specify that the units must be powered by pipeline-quality natural gas; establish that a minimum 20% of the available heat from exhaust gases must be recovered and used elsewhere; and establish emissions standards for CHP units based on the maximum electrical production capacity of the unit. The proposed PBR would exempt a CHP unit at a residential location that generates less than 20 kW of electricity from registration and other requirements except for sections of the proposed rule that define the applicability

of the PBR and the required minimum level of heat recovery. Emission standards under the proposed PBR are structured so that units under 20 kW are not subject to an emission standard. Units with a capacity equal to or greater than 20 kW are subject to an emission standard for NO_X and CO. The proposed PBR will also specify additional operational requirements as well as monitoring and testing requirements.

The proposed PBR provides an additional authorization process for CHP systems. Owners and operators could still choose to comply with the standard permit for EGUs or a case-by-case air permit. From available industry data, staff has determined that the requirements of the proposed PBR are sufficient to cover the typical range of CHP applications. Typical examples of entities that use CHP units are: hospitals, hotels, wastewater treatment plants, chemical plants, and refineries. Based on information from industry representatives, staff anticipates an increasing demand for CHP facilities as a means to provide a localized, efficient source of power and heat for these types of applications.

The agency would use currently available resources to implement the proposed rule. The proposed PBR would cost $100 or $450 rather than the $900 for a standard permit or a case-by-case permit. Staff estimates that there may be as many as 20 additional CHP units that may apply for authorization under the PBR rather than apply under the current standard permit. Agency revenue in Account 151 - Clean Air Account could

increase by $9,000 per year (20 units x $450/year) rather than $18,000 per year if the standard permit for EGUs was used. Any revenue change is not expected to have a significant fiscal impact on the agency.

The proposed PBR is not expected to have a significant fiscal impact on units of local government that operate CHP units. If a CHP unit qualifies for authorization under the proposed PBR, some local governments with populations or districts of 10,000 or fewer residents would pay $100 for a PBR. Other units of local government with more than 10,000 residents are expected to pay $450 for the PBR rather than $900 for a standard permit or a case-by-case permit. Monitoring and testing costs for CHP units authorized by the proposed PBR are expected to be approximately the same as these types of costs for a standard permit. CHP units generating under 20 kW of electricity would be exempt from the monitoring and testing requirements of the proposed PBR. Testing and monitoring costs for CHP units generating 20 kW or more of electricity with certified engines could range from $3,000 to $4,000 the first year, and less than $1,000 per year for required monitoring the second through fifth years. For uncertified engines and turbines, one time testing costs and monitoring could range from $6,000 to $10,000 for the first year, and less than $1,000 for monitoring costs during the second through fifth years.

Public Benefits and Costs

Nina Chamness also determined that for each year of the first five years the proposed new rule is in effect, the public benefit anticipated from the changes seen in the proposed rule will be a less expensive authorization process for stationary natural gas engines and turbines used in CHP units. This could expand available power resources within the state and encourage projects that would improve energy efficiency while continuing to protect human health and the environment.

The proposed PBR is not expected to have a significant fiscal impact on businesses owning or operating CHP units with stationary natural gas engines and turbines, but businesses could experience lower authorization costs if they qualify for the proposed PBR. Typical examples of entities that use CHP units are: hospitals, hotels, wastewater treatment plants, chemical plants, and refineries. The proposed rules are voluntary in nature, and businesses are expected to choose the most economical method of authorization (the proposed PBR, a standard permit, or a case-by-case permit) for their CHP units. Under the proposed PBR, a business would pay $450 for the PBR rather than $900 for a standard permit or a case-by-case permit. Any small businesses are only subject to a fee of $100 for the PBR. Monitoring and testing cost for CHP units authorized by the proposed PBR are expected to be about the same as these types of costs for a standard permit. CHP units generating under 20 kW of electricity would be exempt from the monitoring and testing requirements of the proposed PBR. Testing and monitoring costs for CHP units generating 20 kW or more of electricity with

certified engines could range from $3,000 to $4,000 the first year, and less than $1,000 per year for required monitoring the second through fifth years. For uncertified engines and turbines, one time testing costs and monitoring could range from $6,000 to $10,000 for the first year, and less than $1,000 for monitoring costs during the second through fifth years.

Small Business and Micro-Business Assessment

No adverse fiscal implications are anticipated for small or micro-businesses that own or operate CHP units using a stationary natural gas engine if they meet the requirements of the proposed PBR. A small or micro-business is expected to experience the same cost savings as a large business under the proposed rule. Monitoring and testing costs are expected to be similar as those required by a standard permit, which a small business may also choose as an authorization method instead of the proposed PBR.

Small Business Regulatory Flexibility Analysis

The commission has reviewed this proposed rulemaking and determined that a small business regulatory flexibility analysis is not required because the proposed rule is required to comply with state law and do not adversely affect a small or micro-business in a material way for the first five years that the proposed rule is in effect.

Local Employment Impact Statement

The commission has reviewed this proposed rulemaking and determined that a local employment impact statement is not required because the proposed rule does not adversely affect a local economy in a material way for the first five years that the proposed rule is in effect.

Draft Regulatory Impact Analysis Determination

The commission reviewed the proposed rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225 and determined that the proposed 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 proposed rulemaking constituted a major environmental rule,

a regulatory impact analysis would not be required because the proposed 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 proposed rulemaking does not meet any of the four applicability criteria listed in Texas Government Code, §2001.0225 because: 1) the proposed rulemaking is designed to meet, not exceed the relevant standard set by federal law; 2) parts of the proposed 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 proposed rulemaking is authorized by specific sections of THSC, Chapter 382 (also known as the TCAA), cited in the Statutory Authority section of this preamble.

The specific intent of the proposed 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 invites public comment on the draft regulatory impact analysis determination. Written comments on the draft regulatory impact analysis determination may be submitted to the contact person at the address listed under the Submittal of Comments section of this preamble.

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 proposed 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 proposed PBR will benefit the environment by ensuring that natural gas CHP units covered by the proposed 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.

Written comments on the consistency of this rulemaking may be submitted to the contact person at the address listed under the Submittal of Comments section of this preamble.

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. If the proposed rule is adopted, 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.

Announcement of Hearing

The commission will hold a public hearing on this proposal in Austin on April 3, 2012, at 10:00 am in Room 201S, Building E, at the commission's central office located at 12100 Park 35 Circle. The hearing is structured for the receipt of oral or written comments by interested persons. Individuals may present oral statements when called upon in order of registration. Open discussion will not be permitted during the hearing; however, commission staff members will be available to discuss the proposal 30 minutes prior to

the hearing.

Persons who have special communication or other accommodation needs who are planning to attend the hearing should contact Sandy Wong, Office of Legal Services at (512) 239-1802. Requests should be made as far in advance as possible.

Submittal of Comments

Written comments may be submitted to Bruce McAnally, MC 205, Office of Legal Services, Texas Commission on Environmental Quality, P.O. Box 13087, Austin, Texas 78711-3087, or faxed to (512) 239-4808. Electronic comments may be submitted at: *http://www5.tceq.texas.gov/rules/ecomments/*. File size restrictions may apply to comments being submitted via the eComments system. All comments should reference Rule Project Number 2012-008-106-AI. The comment period closes April 9, 2012. Copies of the proposed rulemaking can be obtained from the commission's Web site at *http://www.tceq.texas.gov/nav/rules/propose_adopt.html*. For further information, please contact Michael Wilhoit, Technical Program Support Section, Air Permits Division, at (512) 239-1222.

SUBCHAPTER W: TURBINES AND ENGINES

§106.513

Statutory Authority

The new rule is proposed 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 proposed 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 proposed 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 generate no more than 5 megawatts (MW) of electricity and 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 exhaust of that 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, add-on controls may not be used to comply with the emission standards of this section.

(5) No more than one CHP unit may be authorized at a site under this section.

(d) Emission Standards.

(1) 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.

(2) A CHP unit with a capacity greater than or equal to 20 kW 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) Compliance with the NO_X standards above may be achieved by taking credit for the heat recovered from the exhaust of the combustion unit. Credit will be at the rate of one 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 monitor NO_X and CO emissions as follows:

(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) Except for rich-burn engines equipped with oxidation-reduction (three-way) catalysts, 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; and

(D) Records of maintenance described in subsection (g)(2) of this section.

(g) Planned Maintenance, Startup, and Shutdown.

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

(2) This permit by rule 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.