

The Texas Commission on Environmental Quality (TCEQ or commission) proposes to amend §106.352.

Background and Summary of the Factual Basis for the Proposed Rule

On January 26, 2011, the commission adopted a new §106.352. Subsections (a) - (k) of the new section consist of updated control, monitoring, and reporting requirements that apply in 23 counties of North Central Texas (Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Denton, Eastland, Ellis, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Shackelford, Stephens, Somervell, Tarrant, and Wise), commonly known as the Barnett Shale Region. Subsection (l) consists of the requirements that existed in the previous version of §106.352 and applies to the remainder of the state's counties.

The new §106.352 is the result of an ongoing, multi-phased evaluation of permits by rule (PBR) and standardized authorizations (standard permits). The goals of this evaluation include: updating administrative and technical requirements; making appropriate changes to registration or notification requirements; ensuring that air emissions from specific facilities are protective of public health and welfare; including practically enforceable record requirements; and allowing the commission to more effectively focus resources on facilities that significantly contribute air contaminants to the atmosphere. To accomplish these goals, the commission provided a minimum setback of oil and gas

facilities from receptors and a method of updating its inventory of existing facilities.

Through this evaluation, the commission determined a need to significantly revise the PBR and standard permit for oil and gas facilities or groups of facilities at a site, which resulted in the January 2011 adoption.

Updating §106.352 was particularly critical for oil and gas site (OGS) in urban locations or in close proximity to the public, and was adopted primarily to better regulate production of oil and natural gas in the Barnett Shale Region.

The designation of the Barnett Shale Region counties was based on the underlying geologic formation as recognized by the Texas Railroad Commission (RRC), the high volume of current and potential drilling sites, and their close proximity to dense urban populations. The implementation of the rule in the Barnett Shale Region gave the commission an opportunity to evaluate its administration in the area that presented the most immediate challenge. This proposed rulemaking is a result of this ongoing evaluation. The updated §106.352 has been in effect since April 1, 2011, and the commission has had the opportunity to evaluate its appropriateness based on population density, the total number and concentration of Barnett Shale formation drilling and producing oil and gas facilities near population centers, and monitoring and compliance records.

The amendment would remove certain counties from the applicability of rules regulating oil and gas facilities in the Barnett Shale Region, allow compliance with local setback ordinances to meet state requirements, and extend the deadline for historical notification of facility location and method of authorization. The proposed amendment would also correct typographic errors.

Section Discussion

As stated in the preamble from the January 26, 2011, adoption, the commission determined that the rule should apply to the area of the state with the greatest number of new or modified facilities located in close proximity to the greatest number of residents. The commission proposes to amend §106.352(a)(1) to remove Archer, Bosque, Coryell, Clay, Comanche, Eastland, Shackelford, and Stephens Counties from the applicability of §106.352(a) - (k). Section 106.352(l) would then apply to the removed counties. Using data from the RRC, the commission evaluated oil and gas operations in the Barnett Shale Counties on population density, and the total number and concentration of Barnett Shale drilling and producing facilities in close proximity to population centers.

The commission has examined monitoring and enforcement data in the counties proposed for removal to confirm that no ambient air quality standards are threatened and that there are no ongoing rule compliance problems. The commission has analyzed

the drilling and production activity in Archer, Bosque, Clay, Comanche, Coryell, Eastland, Shackelford, and Stephens Counties, and the commission proposes to remove these counties based primarily on the relatively low density of Barnett Shale oil and gas facilities near the associated population centers.

In making this proposal, the commission has complied with the applicable requirements of Senate Bill (SB) 1134, 82nd Legislature which requires evaluation of four criteria before adopting or amending a PBR or standard permit. First, the legislation requires a regulatory analysis as provided by Texas Government Code, §2001.0225. The commission has performed this analysis in accordance with its established procedures for rulemaking and concluded that this proposal is not a major environmental rule, because it does not affect the economy of the state or a portion of the state in a material way. The second and third criteria involve an evaluation of air quality monitoring and modeling data to establish any emissions limits or emissions related requirements. This rulemaking would not establish or revise any emissions limit or emissions related requirements. Therefore, the commission has determined that these criteria are not applicable. However, the commission has examined monitoring data from the counties proposed for removal and has determined that the requirements of §106.352(l) will ensure that the purposes of the Texas Clean Air Act are not contravened and that there will be no threat to public health.

Fourth, the commission is required to consider whether the requirements of a permit should be imposed only on facilities that are located in a particular geographic region of the state. The commission has complied with this requirement, considering whether the requirements of §106.352(a) - (k) can be made applicable to a smaller geographic region of the state. Oil and gas facilities in the removed counties would instead be required to comply with §105.352(l), applicable to non-Barnett Shale Counties.

The commission proposes to amend §106.352(b)(7)(B) and (f)(1) to extend the deadline for owners and operators of existing oil and gas facilities to provide notification to the commission of the facility location and method of authorization from January 1, 2013 to January 5, 2015. The January 1, 2013, date was originally tied to the date for authorization of maintenance, startup, and shutdown (MSS) emissions (January 5, 2012). However, SB 1134, codified in Texas Health and Safety Code (THSC), §382.051962, extended the MSS authorization deadline to January 5, 2014. Therefore, to remain consistent with the change in timing for the MSS authorization, the commission proposes to extend the historical notification deadline. Because this proposed rulemaking does not specifically address the authorization of MSS, the deadlines for submission of applications to authorize MSS in THSC, §382.051962(c) do not apply.

The commission proposes to amend §106.352(d)(2)(C) and (F) to correct a

typographical error in each subparagraph by inserting the word "be" between the words "otherwise" and "authorized" in both subsections.

The commission proposes to amend §106.352(e)(2) to account for local ordinances which require an equal or greater separation of oil and gas facilities from a receptor. The Barnett Shale Region contains some areas of significant population density and significant concentrations of drilling and production. Local governments may determine that specific conditions within their jurisdiction require a greater setback to ensure the protection of their citizens. This proposal clarifies the measurement of minimum distance requirements §106.352(e)(2), where such a local ordinance exists requiring equal or greater set-back distances from receptors. This proposal requires no additional separation should such a local ordinance exist, and the commission would consider compliance with the ordinance to meet both the separation required from a receptor and a property line as stated in §106.352(e)(2). This revision will provide flexibility for operators located in urban areas, on small well pad sites, with difficulty meeting property line distance limitations while ensuring continued protection of the human health and the environment. The commission also proposes to amend §106.352(e)(2)(B) to add the words "less than" between the word "use" and the number "50" since an existing separation of 50 feet would require no action from the oil and gas owner or operator.

The commission proposes to amend §106.352(k)(2)(A) to refer to the TCEQ internet Web page instead of the "commissioner's internet Web page."

The commission proposes to amend §106.352(l)(5) to refer to the "executive director" instead of the "Office of Permitting and Registration" as that office designation is obsolete.

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 as a result of the administration or enforcement of the proposed rule. The agency will use currently available resources to implement the proposed rule. The proposed rule will not have a fiscal impact on other state agencies or units of local government since these governmental entities do not typically own or operate the types of oil and gas facilities affected by the proposed rule.

For purposes of the application of TCEQ rules, the Barnett Shale Region is currently made up of the following counties: Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Denton, Eastland, Ellis, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Shackelford, Stephens, Somervell, Tarrant, and Wise. The agency has continued its evaluation of PBRs and standardized authorizations issued in the Barnett Shale

Region as part of its effort to ensure that agency resources are focused on facilities that emit air contaminants near concentrations of population. The proposed rule would affect new or modified oil and gas facilities in certain counties of the Barnett Shale Region. The commission is not seeking to make more stringent or expand control requirements on the oil and gas industry and is making this proposal in compliance with the applicable requirements of SB 1134 as codified in THSC, §382.051961.

The proposed rule would have three main provisions: 1) A clarification that compliance with a local ordinance passed by a unit of local government requiring more than a 50-foot separation between an oil and gas facility and receptor in the Barnett Shale Region will meet all required distances for separation, including separation from property lines; 2) Archer, Bosque, Clay, Comanche, Coryell, Eastland, Shackelford, and Stephens Counties would be removed from the list of counties in the definition of the Barnett Shale Region; 3) and the deadline for owners and operators of existing facilities to provide notification of their location and method of authorization would be extended from January 1, 2013 to January 5, 2015. Examples of affected oil and gas facilities would include new or modified compressor stations, pipelines, and wellheads. The proposed rule would not have a fiscal impact on units of local government.

Public Benefits and Costs

Nina Chamness also determined that for each year of the first five years the proposed

rule is in effect, the public benefit anticipated from the changes seen in the proposed rule will be greater clarity regarding the separation distance between oil and gas facilities and receptors if there is an applicable local ordinance. Examples of oil and gas facilities affected by the proposed rule are new or modified compressor stations, pipelines, and wellheads in Archer, Bosque, Clay, Comanche, Coryell, Eastland, Shackelford, and Stephens Counties. Businesses that own these types of facilities in the counties removed from the Barnett Shale Region could save as much as \$11,500 per facility as a result of the proposed rule based on cost estimates for controls from the analysis of amended §106.352 as adopted in January 2011. As of 2011, there are approximately 7,000 natural gas facilities included in the Barnett Shale Region.

Small Business and Micro-Business Assessment

No adverse fiscal implications are anticipated for small or micro-businesses as a result of the proposed rule. Small businesses that own or operate oil and gas facilities in the counties that would be removed from the definition of the Barnett Shale Region could save as much as \$11,500 per facility under the proposed rule.

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 does 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 rulemaking 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 remove Archer, Bosque, Clay, Comanche, Coryell, Eastland, Shackelford, and Stephens Counties from the list of Barnett Shale Counties subject to §106.352(a) - (k), add clarifying language to the PBR and oil and gas standard permit the measurement of minimum distance requirements, and extend the deadline for the

historical notification required in §106.352(f)(1) from January 1, 2013 to January 5, 2015, 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.

Furthermore, while the proposed rulemaking does not constitute a major environmental rule, even if it did, 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 which: "(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." Specifically, the proposed rule does not meet any of the four applicability criteria listed in Texas Government Code, §2001.0225 because: 1) the proposed rulemaking is not designed to exceed any relevant standard set by federal law; 2) the rulemaking does not exceed an express requirement of state law; 3) no contract or delegation agreement covers the topic that is the subject of this proposed rulemaking; and 4) the proposed rulemaking is authorized by specific sections of THSC, Chapter 382

(also known as the Texas Clean Air Act), and the Texas Water Code, which are cited in the STATUTORY AUTHORITY section of this preamble.

The commission's interpretation of the regulatory impact analysis requirements is also supported by a change made to the Texas Administrative Procedure Act (APA) by the legislature in 1999. In an attempt to limit the number of rule challenges based upon APA requirements, the legislature clarified that state agencies are required to meet these sections of the APA against the standard of "substantial compliance" as required in Texas Government Code, §2001.035. The legislature specifically identified Texas Government Code, §2001.0225 as falling under this standard. The commission has substantially complied with the requirements of Texas Government Code, §2001.0225.

Additionally, SB 1134 applies to this rulemaking. SB 1134 states that the commission may not amend an existing PBR or an existing standard permit relating to an oil and gas facility unless the commission: 1) conducts a regulatory analysis as provided by Texas Government Code, §2001.0225; 2) determines, based on the evaluation of credible air quality monitoring data, that the emissions limits or other emissions-related requirements of the permit are necessary to ensure that the intent of the Texas Clean Air Act is not contravened, including the protection of the public's health and physical property; 3) establishes any required emissions limits or other emissions-related requirements based on: (A) the evaluation of credible air quality monitoring data; and

(B) credible air quality modeling that is not based on the worst-case scenario of emissions or other worst-case modeling scenarios unless the actual air quality monitoring data and evaluation of that data indicate that the worst-case scenario of emissions or other worst-case modeling scenarios yield modeling results that reflect the actual air quality monitoring data and evaluation; and 4) considers whether the requirements of the permit should be imposed only on facilities that are located in a particular geographic region of the state.

The commission has conducted a regulatory analysis in accordance Texas Government Code, §2001.0225 as previously described. The executive director examined monitoring and enforcement data in the counties proposed for removal to confirm that no ambient air quality standards are threatened and that there are no ongoing rule compliance problems. Finally, the proposed rule does not establish an emission limit or emission-related requirements and is proposed in accordance with SB 1134.

The commission invites public comment regarding the draft regulatory impact analysis determination during the public comment period. 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 evaluated the proposed rulemaking and performed an analysis of whether the proposed rulemaking constitutes a taking under Texas Government Code, Chapter 2007. The commission's preliminary assessment indicates Texas Government Code, Chapter 2007 does not apply.

Under Texas Government Code, §2007.002(5), taking means: "(A) a governmental action that affects private real property, in whole or in part or temporarily or permanently, in a manner that requires the governmental entity to compensate the private real property owner as provided by the Fifth and Fourteenth Amendments to the United States Constitution or Section 17 or 19, Article I, Texas Constitution; or (B) a governmental action that: (i) affects an owner's private real property that is the subject of the governmental action, in whole or in part or temporarily or permanently, in a manner that restricts or limits the owner's right to the property that would otherwise exist in the absence of the governmental action; and (ii) is the producing cause of a reduction of at least 25 percent in the market value of the affected private real property, determined by comparing the market value of the property as if the governmental action is not in effect and the market value of the property determined as if the governmental action is in effect."

Promulgation and enforcement of the proposed rulemaking would be neither a statutory nor a constitutional taking of private real property. The primary purpose of the

rulemaking is to remove Archer, Bosque, Clay, Comanche, Coryell, Eastland, Shackelford, and Stephens Counties from the list of Barnett Shale Counties subject to §106.352(a) - (k), add clarifying language to the PBR and oil and gas standard permit the measurement of minimum distance requirements, and extend the deadline for the historical notification required in §106.352(f)(1) from January 1, 2013 to January 5, 2015. The proposed rulemaking does not affect a landowner's rights in private real property because this rulemaking does not burden, restrict, or limit the owner's right to property, nor does it reduce the value of any private real property by 25% or more beyond that which would otherwise exist in the absence of the regulations. Therefore, the proposed rule would not constitute a taking under Texas Government Code, Chapter 2007.

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 30 TAC Chapter 281, Subchapter B, Consistency with the Texas Coastal Management Program. As required by §281.45(a)(3), Actions Subject to Consistency with the Goals and Policies of the Texas Coastal Management Program (CMP), and 31 TAC §505.11(b)(2), 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), Goals). This rule will not authorize new emissions in coastal areas. Therefore, in accordance with 31 TAC §505.22(e), Consistency Required for New Rules and Rule Amendments Subject to the Coastal Management Program, 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 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 must, consistent with the revision process in Chapter

122, include any changes made using the amended Chapter 106 requirements into their operating permit.

Announcement of Hearing

The commission will hold a public hearing on this proposal on July 10, 2012, at 7:00 p.m. in Fort Worth, at the TCEQ Dallas/Fort Worth Regional Office, located at 2309 Gravel Drive, Fort Worth, Texas. 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. This hearing will be held in conjunction with a public meeting on similar proposed revisions to the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities.

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 2012-020-106-AI. The comment period closes on July 16, 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 Beecher Cameron, Air Permits Division, Technical Support Section, at (512) 239-1495 or beecher.cameron@tceq.texas.gov.

SUBCHAPTER O: OIL AND GAS

§106.352

Statutory Authority

The amendment is proposed under Texas Water Code (TWC), §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 TWC; 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 amendment 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; §382.051962, which extended the deadline for owners or operators of oil and gas facilities to authorize maintenance, startup, and shutdown emissions to January 5, 2014; §382.051963 which authorizes the commission to obtain

information about oil and gas authorizations, including location; and §382.057, concerning Exemption, which authorizes exemptions from permitting.

The proposed amendment implements THSC, §§382.002, 382.011, 382.012, 382.017, 382.051, 382.05196, and 382.057.

§106.352. Oil and Gas Handling and Production Facilities.

(a) Applicability. This section applies to all stationary facilities, or groups of facilities, at a site which handle gases and liquids associated with the production, conditioning, processing, and pipeline transfer of fluids or gases found in geologic formations on or beneath the earth's surface including, but not limited to, crude oil, natural gas, condensate, and produced water with the following conditions:

(1) The requirements in subsections (a) - (k) of this section are applicable only for new projects and related facilities located in the Barnett Shale ([Archer, Bosque, Clay, Comanche,] Cooke, [Coryell,] Dallas, Denton, [Eastland,] Ellis, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, [Shackelford, Stephens,] Somervell, Tarrant, and Wise Counties) on or after April 1, 2011. For all other new projects and related facilities in all other counties of the state, subsection (l) of this section is applicable.

(2) Only one Oil and Gas Handling and Production Facilities permit by rule (PBR) for an oil and gas site (OGS) may be claimed or registered for each combination of dependent facilities and authorizes all facilities in sweet or sour service. This section may not be used if operationally dependent facilities are authorized by the Air Quality Standard Permit for Oil and Gas Sites, or a permit under §116.111 of this title (relating to General Application). Existing authorized facilities, or groups of facilities, at an OGS under this section which are not changing certified character or quantity of emissions must only meet subsections (i) and (k) of this section (protectiveness review and planned maintenance, startup, and shutdown (MSS) requirements) and otherwise retain their existing authorization. Except for planned MSS activities which must meet the requirements of subsection (i) of this section, any combination of dependent facilities with a permit under §116.111 of this title cannot also claim this section for any new facility, or changes to an existing facility, which handles (or is related to the processing of) crude oil, condensate, natural gas, or any other petroleum raw material, product, or by-product.

(3) 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.

(4) Emissions from upsets, emergencies, or malfunctions are not authorized by this section. This section does not regulate methane, ethane, or carbon dioxide.

(b) Definitions and Scope.

(1) Facility is a discrete or identifiable structure, device, item, equipment, or enclosure that constitutes or contains a stationary source. Stationary sources associated with a mine, quarry, drilling, or a well test lasting less than 72 hours are not considered facilities.

(2) Receptor includes any building which is in use as a single or multi-family residence, school, day-care, hospital, business, or place of worship at the time this section is registered. A residence is a structure primarily used as a permanent dwelling. A business is a structure that is occupied for at least eight [8] hours a day, five [5] days a week, and does not include businesses who are handling or processing materials as described in subsection (a) of this section. This term does not include structures occupied or used solely by the owner or operator of the OGS facility, or the mineral rights owner of the property upon which the OGS facility is located. All measurements of distance to receptors shall be taken from the emission release point at the OGS facility that is nearest to the point on the building that is nearest to the OGS facility.

(3) An OGS is defined as all facilities which meet each of the following:

(A) Located on contiguous or adjacent properties;

(B) Under common control of the same person (or persons under common control); and

(C) Designated under same two digit standard industrial classification (SIC) codes.

(4) For purposes of determining applicability of Chapter 122 of this title (relating to Federal Operating Permits Program), the definitions of §122.10 of this title (relating to General Definitions), apply.

(5) A project under this section is defined as the following and must meet all requirements of this section prior to construction or implementation of changes:

(A) Any new facility or new group of operationally dependent facilities at an OGS;

(B) Physical changes to existing authorized facilities or group of facilities at an OGS which increase the potential to emit over previously certified emission limits; or

(C) Operational changes to existing authorized facilities or group of facilities at an OGS which increase the potential to emit over previously certified emission limits.

(6) For purposes of registration under this section, the following facilities shall be included:

(A) All facilities or groups of facilities at an OGS which are operationally dependent on each other;

(B) Facilities must be located within a 1/4 mile of a project emission point, vent, or fugitive component, except for those components excluded in subparagraph (C) of this paragraph;

(C) If piping or fugitive components are the only connection between facilities and the distance between facilities exceeds 1/4 mile, then the facilities are considered separate for purposes of this registration;

(D) The boundaries of the registration become fixed at the time this section is claimed and registered. No individual facility may be authorized under more than one registration;

(E) Any facility or group of facilities authorized under an existing PBR registration which is operationally dependent on a project must be revised to incorporate the project. Existing authorized facilities, or group of facilities, at an OGS under this section which are not changing certified character or quantity of emissions must only meet subsections (i) and (k) of this section (the protectiveness review and planned MSS requirements) and otherwise retain their existing authorization; and

(F) All facilities at an OGS registered under this section must collectively emit less than or equal to 250 tons per year (tpy) of nitrogen oxides (NO_x) or carbon monoxide (CO); 15 tpy of particulate matter with less than 10 microns (PM₁₀); 10 tpy of particulate matter less than 2.5 microns (PM_{2.5}); and 25 tpy of volatile organic compounds (VOC), sulfur dioxide (SO₂), hydrogen sulfide (H₂S), or any other air contaminant except carbon dioxide, water, nitrogen, methane, ethane, hydrogen, and oxygen.

(7) For purposes of all previous claims of this section (or any previous version of this section) where no project is occurring:

(A) existing authorized facilities, or group of facilities, at an OGS must meet only subsection (i) of this section no later than January 5, 2012; and

(B) submit a notification in accordance with subsection (f) of this section no later than January 5, 2015 [January 1, 2013].

(8) For purposes of ensuring protection of public health and welfare and demonstrating compliance with applicable ambient air standards and effects screening levels (ESLs), the impacts analysis as specified in subsection (k) of this section must be completed.

(A) All impacts analysis must be done on a contaminant-by-contaminant basis for any net project increases. If a claim under this section is only for planned MSS under subsection (i) of this section, the analysis shall evaluate planned MSS scenarios only.

(B) Hourly and annual emissions shall be limited based on the most stringent of subsections (g), (h), or (k) of this section.

(c) Authorized Facilities, Changes, and Activities.

(1) For existing OGS which are authorized by previous versions of this section.

(A) A project requires registration unless otherwise specified.

(B) The following projects do not require registration, but must comply with best management practices (BMP) in subsection (e) of this section, compliance demonstrations in subsections (i) and (j) of this section, and must be incorporated into the registration at the next revision or certification:

(i) Addition of any piping, fugitive components, any other new facilities, that increase actual emissions less than or equal to 1.0 tpy VOC, 5.0 tpy NO_x, 0.01 tpy benzene, and 0.05 tpy H₂S over a rolling 12-month period;

(ii) Changes to any existing facilities that increase certified emissions less than or equal to 1.0 tpy VOC, 5.0 tpy NO_x, 0.01 tpy benzene, and 0.05 tpy H₂S over a rolling 12-month period;

(iii) Total increases over a rolling 60-month period of time that are less than or equal to 5.0 tpy VOC or NO_x, 0.05 tpy benzene, or 0.1 tpy H₂S;

(iv) Addition of any new engine rated less than 100 horsepower (hp); or

(v) Replacement of any facility if the new facility does not increase the previous actual or certified emissions.

(C) For facilities authorized under §116.111 of this title, only records of MSS as specified in this section must be kept and this section may only be used for planned MSS for the facility types specified in this section.

(2) All authorizations under this section shall meet the following:

(A) new, changed, or replacement facilities shall not exceed the thresholds for major source or major modification as defined in §116.12 of this title (relating to Nonattainment and Prevention of Significant Deterioration Review Definitions), and in Federal Clean Air Act, §112(g) or §112(j);

(B) all facilities shall comply with all applicable 40 Code of Federal Regulations (CFR), Parts 60, 61, and 63 requirements for New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and Maximum Achievable Control Technology (MACT); and

(C) all facilities shall comply with all applicable requirements of Chapters 111, of this title (relating to Control of Air Pollution from Visible Emissions and Particulate Matter), 112 of this title (relating to Control of Air Pollution from Sulfur Compounds), 113 of this title (relating to Standards of Performance for Hazardous Air Pollutants and for Designated Facilities and Pollutants), 115 of this title (relating to Control of Air Pollution from Volatile Organic Compounds), and 117 of this title (relating to Control of Air Pollution from Nitrogen Compounds).

(3) To be eligible for this PBR, in addition to the requirements found in §106.4 of this title (relating to Requirements for Permitting by Rule), an applicant:

(A) shall meet all applicable requirements as set forth in this section;

(B) shall not misrepresent or fail to fully disclose all relevant facts in obtaining the permit; and

(C) shall not be indebted to the state for failure to make payment of penalties or taxes imposed by the statutes or rules within the commission's jurisdiction.

(D) Notwithstanding any limitations in §50.131(c) of this title (relating to Purpose and Applicability), a person may file a Motion to Overturn under the procedures set forth in §50.139 of this title (relating to Motion to Overturn Executive Director's Decision) in order to seek commission review of any denial of a PBR for failing to meet the conditions set forth in this paragraph.

(4) This paragraph covers groups of facilities typically associated with wellheads, pump-jacks, Christmas trees, metering stations, and other similar facilities handling or containing crude oil, condensate, natural gas, or a mixture of these materials (examples include, but are not limited to, stripper/marginal wells producing up to 10 barrels of oil equivalent per day, natural gas up to 60,000 cubic feet per day, or high pressure gas wells). The following projects and facilities are authorized and must only comply with subsection (e)(1) and (2) of this section, and applicable portions of subsection (j) of this section:

(A) Claims under this paragraph must include all facilities or groups of facilities at an OGS which are operationally dependent on each other and located within a 1/4 mile of a project emission point, vent, or fugitive component. If piping or fugitive components are the only connection between facilities and the distance between facilities exceeds 1/4 mile, then the facilities are considered separate for purposes of this paragraph.

(B) A site-wide combination of engines which meet the following:

(i) up to 450 hp if fueled by sweet gas;

(ii) up to 100 hp if fueled by sour gas containing not more than 10,000 parts per million by weight (ppmw) H₂S; or

(iii) up to 20 hp fueled by sour gas containing more than 10,000 ppmw but not more than 50,000 ppmw H₂S.

(C) For any one of the following combinations of facilities:

(i) only piping and fugitive components handling natural gas up to a maximum of 135 valves, 135 open-ended lines, any combination of connectors and flanges up to 2,000 components, and 135 component types otherwise not specified;
or

(ii) only piping and fugitive components handling liquids or gas up to a maximum of 25 valves, 25 open-ended lines, any combination of connectors and flanges up to 2,000 components, and 25 component types otherwise not specified;

(iii) only piping and fugitive components handling liquids or gas up to a maximum of four pump seals; four open-ended lines; and any combination of valves, flanges, and connectors up to 225 components; or

(iv) separators used solely to separate crude oil, condensate, and natural gas (which are routed directly to a sales pipeline) from produced water. Tanks used and handling only produced water up to 1,205 barrels per day. All associated piping and fugitive components up to a maximum of five pump seals; five open-ended lines; and any combination of valves, flanges, and connectors totaling 150 components in VOC service and 500 components in water service; or

(v) separators used solely to separate crude oil, condensate, and natural gas (which are routed directly to a sales pipeline) from produced water. Tanks used and handling only produced water up to 580 barrels per day. All associated piping and fugitive components up to a maximum of two pump seals; two open-ended lines; and any combination of valves, flanges, and connectors totaling 230 components in VOC service and 500 components in water service.

(d) Facilities and Exclusions.

(1) Only the following specific facilities and groups of facilities have been evaluated for this PBR, along with supporting infrastructure equipment and facilities, and may be included in a registration for this section:

(A) fugitive components, including valves, pressure relief valves, pipe flanges and connectors, pumps, compressors, stuffing boxes, instrumentation and meters, natural gas driven pneumatic pumps, and other similar devices with seals that separate process and waste material from the atmosphere and the associated piping;

(B) separators, including all gas, oil, and water physical separation units;

(C) treatment and processing equipment, including heater-treaters, methanol injection, glycol dehydrators, molecular or mole sieves, amine sweeteners, H₂S scavenger chemical reaction vessels for sulfur removal, and iron sponge units;

(D) cooling towers and associated heat exchangers;

(E) gas recovery units, including cryogenic expansion, absorption, adsorption, heat exchangers and refrigeration units;

(F) combustion units, including engines, turbines, boilers, reboilers, and heaters;

(G) storage tanks for crude oil, condensate, produced water, fuels, treatment chemicals, slop and sump oils, and pressure tanks with liquefied petroleum gases;

(H) surface support facilities associated with underground storage of gas or liquids;

(I) truck loading equipment;

(J) control equipment, including vapor recovery systems, glycol and amine reboilers, condensers, flares, vapor combustors, and thermal oxidizers; and

(K) temporary facilities used for planned maintenance, and temporary control devices for planned startups and shutdowns.

(2) Exclusions. The following are not authorized under this section:

(A) sour water strippers or sulfur recovery units;

(B) carbon dioxide hot carbonate processing units;

(C) water injection facilities. These facilities may otherwise be authorized by §106.351 of this title (relating to Salt Water Disposal (Petroleum));

(D) liquefied petroleum gases, crude oil, or condensate transfer or loading into or from railcars, ships, or barges. These facilities may otherwise be authorized by §106.261 of this title (relating to Facilities (Emission Limitations)) and §106.262 of this title (relating to Facilities (Emission and Distance Limitations));

(E) incinerators for solid waste destruction;

(F) remediation of petroleum contaminated water and soil. These facilities may otherwise be authorized by §106.533 of this title (relating to Remediation);
and

(G) cooling towers and heat exchangers with direct contact with gaseous or liquid process streams containing VOC, H₂S, halogens or halogen compounds, cyanide compounds, inorganic acids, or acid gases.

(e) BMP and Minimum Requirements. For any new project, and any associated emission control equipment registered under this section, paragraphs (1) - (5) of this subsection shall be met as applicable. These requirements are not applicable to existing, unchanging facilities. Equipment design and control device requirements listed in paragraphs (6) - (12) of this subsection only apply to those that are chosen by the operator to meet the limitations of this section.

(1) All facilities which have the potential to emit air contaminants must be maintained in good working order and operated properly during facility operations. Each operator shall establish and maintain a program to replace, repair, and/or maintain facilities to keep them in good working order. The minimum requirements of this program shall include:

(A) Compliance with manufacturer's specifications and recommended programs applicable to equipment performance and effect on emissions, or alternatively, an owner or operator developed maintenance plan for such equipment that is consistent with good air pollution control practices;

(B) cleaning and routine inspection of all equipment; and

(C) replacement and repair of equipment on schedules which prevent equipment failures and maintain performance.

(2) Any facility shall be operated at least 50 feet from any property line or receptor (whichever is closer to the facility). This distance limitation does not apply as specified in subparagraphs (A) - (C) of this paragraph. Compliance with local set-back ordinances with distance requirements greater than or equal to 50 feet between the facility and a receptor satisfies all separation requirements of this paragraph. [This distance limitation does not apply to the following:]

(A) any fugitive components that are used for isolation and/or safety purposes may be located at 1/2 of the width of any applicable easement;

(B) any facility at a location for which the distance requirements were satisfied at the time this section is claimed, registered, or certified (provided that the authorization was maintained) regardless of whether a receptor is subsequently built or put to use less than 50 feet from any OGS facility; or

(C) existing facilities which are located less than 50 feet from a property line or receptor when constructed and previously authorized. If modified or replaced the operator shall consider, to the extent that good engineering practice will

permit, moving these facilities to meet the 50-foot requirement. Replacement facilities must meet all other requirements of this section.

(3) Engines and turbines shall meet the emission and performance standards listed in Table 6 in subsection (m) of this section and the following requirements:

(A) liquid fueled engines used for back-up power generation and periodic power needs at the OGS are authorized if the fuel has no more than 0.05% sulfur and the engine is operated less than 876 hours per rolling 12-month period;

(B) engines and turbines used for electric generation more than 876 hours per rolling 12-month period are authorized if no reliable electric service is readily available and Table 6 in subsection (m) of this section is met. In all other circumstances, electric generators must meet the technical requirements of the Air Quality Standard Permit for Electric Generating Unit (EGU) (not including the EGU standard permit registration requirements) and the emissions shall be included in the registration under this section;

(C) all applicable requirements of Chapter 117 of this title (relating to Control of Air Pollution from Nitrogen Compounds);

(D) all applicable requirements of 40 CFR Parts 60 and 63; and

(E) compression ignition engines that are rated less than 225 kilowatts (300 hp) and emit less than or equal to the emission tier for an equivalent-sized model year 2008 non-road compression ignition engine located at 40 CFR §89.112, Table 1 are authorized.

(4) Open-topped tanks or ponds containing VOCs or H₂S are allowed up to a potential to emit equal to 1.0 tpy of VOC and 0.1 tpy of H₂S.

(5) The following shall apply to all fugitive components at the site associated with the project:

(A) All components shall be physically inspected quarterly for leaks.

(B) All components found to be leaking shall be repaired. Every reasonable effort shall be made to repair a leaking component. All leaks not repaired immediately shall be tagged or noted in a log. At manned sites, leaks shall be repaired no later than 30 days after the leak is found. At unmanned sites, leaks shall be repaired no later than 60 days after the leak is found. If the repair of a component would require a

unit shutdown, which would create more emissions than the repair would eliminate, the repair may be delayed until the next shutdown.

(C) Tank hatches, not designed to be completely sealed, shall remain closed (but not completely sealed in order to maintain safe design functionality) except for sampling, gauging, loading, unloading, or planned maintenance activities.

(D) To the extent that good engineering practices will permit, new and reworked valves and piping connections shall be located in a place that is reasonably accessible for leak checking during plant operation. Underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

(6) When leak detection and repair (LDAR) fugitive monitoring is chosen by the operator, Table 9, in subsection (m) of this section, shall apply. In addition, all components shall be physically inspected at least weekly by operating personnel walk-through.

(7) Tanks and vessels that utilize a paint color to minimize the effects of solar heating (including, but not limited to, white or aluminum):

(A) to meet this requirement the solar absorptance should be 0.43 or less, as referenced in Table 7.1 - 6 in Compilation of Air Pollutant Emission Factors (AP-42);

(B) paint shall be applied according to paint producers recommended application requirements if provided and in sufficient quantity as to be considered solar resistant;

(C) paint coatings shall be maintained in good condition and will not compromise tank integrity. Minimal amounts of rust may be present not to exceed 10% of the external surface area of the roof or walls of the tank and in no way may compromise tank integrity. Additionally, up to 10% of the external surface area of the roof or walls of the tank or vessel may be painted with other colors to allow for identification and/or aesthetics;

(D) for tanks and vessels purposefully darkened to create the process reaction and help condense liquids from being entrained in the vapor or are in an area whereby a local, state, federal law, ordinance, or private contract predating this section's effective date establishes in writing tank and vessel colors other than white, these requirements do not apply.

(8) All emission estimation methods including but not limited to computer programs such as GRI-GLYCalc, AmineCalc, E&P Tanks, and Tanks 4.0, must be used with monitoring data generated in accordance with Table 8 in subsection (m) of this section where monitoring is required. All emission estimation methods must also be used in a way that is consistent with protocols established by the commission or promulgated in federal regulations (NSPS, NESHAPS). Where control is relied upon to meet subsection (k) of this section, control monitoring is required.

(9) Process reboilers, heaters, and furnaces that are also used for control of waste gas streams:

(A) may claim 50% to 99% destruction efficiency for VOCs and H₂S depending on the design and level of monitoring applied. The 90% destruction may be claimed where the waste gas is delivered to the flame zone or combustion fire box with basic monitoring as specified in subsection (j) of this section. Any value greater than 90% and up to 99% destruction efficiency may be claimed where enhanced monitoring and/or testing are applied as specified in subsection (j) of this section;

(B) if the waste gas is premixed with the primary fuel gas and used as the primary fuel in the device through the primary fuel burners, 99% destruction may be claimed with basic monitoring as specified in subsection (j) of this section;

(C) in systems where the combustion device is designed to cycle on and off to maintain the designed heating parameters, and may not fully utilize the waste gas stream, records of run time and enhanced monitoring are required to claim any run time beyond 50%.

(10) Vapor recovery Units (VRUs) may claim up to 100% control. The control efficiency is based on whether it is a mechanical VRU (mVRU) or a liquid VRU (lVRU). The VRUs must meet the appropriate design, monitoring, and recordkeeping in Table 7 and Table 8 in subsection (m) of this section.

(11) Flares used for control of emissions from production, planned MSS, emergency, or upset events may claim design destruction efficiency of 98%. 99% may be claimed for destruction of compounds containing only carbon, hydrogen, and oxygen with no more than three carbon atoms. All flares must be designed and operated in accordance with the following:

(A) meet specifications for minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring found in 40 CFR §60.18;

(B) if necessary to ensure adequate combustion, sufficient gas shall be added to make the gases combustible;

(C) an infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes;

(D) an automatic ignition system may be used in lieu of a continuous pilot;

(E) flares must be lit at all times when gas streams are present;

(F) fuel for all flares shall be sweet gas or liquid petroleum gas except where only field gas is available and it is not sweetened at the site; and

(G) flares shall be designed for and operated with no visible emissions, except for periods not to exceed a total of five minutes during any two consecutive hours. Acid gas flares which must comply with opacity limits and records in accordance with §111.111(a)(4) of this title (relating to Requirements for Specified Sources), regarding gas flares, are exempt from this visible emission limitation.

(12) Thermal oxidation and vapor combustion control devices:

(A) may claim design destruction efficiency from 90% to 99.9% for VOCs and H₂S depending on the design and the level of monitoring and testing applied;

(B) a device designed for the variability of the waste gas streams it controls with basic monitoring to indicate oxidation or combustion is occurring when waste gas is directed to the device may claim 90% destruction efficiency;

(C) devices with intermediate monitoring, designed for the variability of the waste gas streams they control, with a fire box or fire tube designed to maintain a temperature above 1,400 degrees Fahrenheit (F) for 0.5 seconds, residence time; or designed to meet the parameters of a flare with minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring as found in 40 CFR §60.18, but within a full or partial enclosure may claim a design destruction efficiency of 90% to 98%;

(D) devices with enhanced monitoring and ports and platforms to allow stack testing may claim a 99% efficiency where the devices are designed for the variability of the waste gas streams they control, with a fire box or fire tube designed to maintain a temperature above 1,400 degrees F for 0.5 seconds, residence time;

(E) devices that can claim 99% destruction efficiency may claim 99.9% destruction efficiency if stack testing is conducted and confirms the efficiency and the enhanced monitoring is adjusted to ensure the continued efficiency. Temperature and residence time requirements may be modified if stack testing is conducted to confirm efficiencies.

(f) Notification, Certification, and Registration Requirements.

(1) For all previous claims of this section (or any previous version of this section) existing authorized facilities, or group of facilities, identified in subsection (b)(7) of this section must submit a notification no later than January 5, 2015 [January 1, 2013]. Facilities or groups of facilities which meet subsection (c)(4) of this section do not have to meet the following notification requirements:

(A) For actively operating facilities which have never been registered with the commission, submit updated Core Data and basic identifying information (previously claimed historical versions of this section and lease name or well numbers as provided to the Texas Railroad Commission) through ePermits using the "APD OGS Historical Notification."

(B) For those facilities which have previously registered with the commission and updates are needed to the commission's Central Registry (CR), submit a hard copy of a Core Data Form with an attachment listing identifying information (previously claimed historical versions of this section and lease name or well numbers as provided to the Texas Railroad Commission). If no updates to CR are required, no further action is needed.

(C) No fee is required for this notification.

(2) If no other changes, except for authorizing planned MSS, occur at an existing site under this section, or any previous version of this section, the following apply no later than January 5, 2012:

(A) Records demonstrating compliance with subsection (i) of this section must be kept;

(B) If the existing OGS is certified, an addendum to the OGS certification may be filed using Form APD-CERT. No fee is required for this updated certification; and

(C) Planned MSS does not require registration if no other project is occurring, and shall be incorporated at the next revision or update to a registration under this section after January 5, 2012.

(3) For facilities authorized under §116.111 of this title, only records of MSS as specified in this section must be kept. Planned MSS shall be incorporated into the permit at the next permit renewal or amendment after January 5, 2012.

(4) Prior to construction or implementation of changes for any project which meets this section, a notification shall be submitted through the ePermits system. This notification shall include the following:

(A) Identifying information (Core Data) and a general description of the project must be submitted through ePermits (or if not available, hard-copy) using the "APD OGS New Project Notification."

(B) A fee of \$25 for small businesses (as defined in §106.50 of this title (relating to Registration Fees for Permits by Rule), or \$50 for all others must be submitted through the commission's ePay system.

(5) For any registration which meets the emission limitations of Level 1 as required in subsection (g) of this section:

(A) Within 180 days after start of operation or implemented changes (whichever occurs first), the facilities must be registered through ePermits form "APD OGS PBR Level 1 and 2 Registration" (or if not available, submittal of hard-copy).

(B) This registration shall include a detailed summary of maximum emissions estimates based on:

(i) site-specific or defined representative gas and liquid analysis;

(ii) equipment design specifications and operations;

(iii) material type and throughput;

(iv) other actual parameters essential for accuracy for determining emissions; and

(v) documentation demonstrating compliance with all applicable requirements of this section.

(C) The fee for this registration shall be \$25 for small businesses, as defined in §106.50 of this title, or \$175 for all others.

(6) For any registration which meets the emission limitations of Level 2 as required in subsection (h) of this section:

(A) Within 90 days after start of operation or implemented changes (whichever occurs first), the facilities must be registered through ePermits form "APD OGS PBR Level 1 and 2 Registration" (or if not available, submittal of hard-copy).

(B) This registration shall include a detailed summary of maximum emissions estimates based on:

(i) site-specific or defined representative gas and liquid analysis;

(ii) equipment design specifications and operations;

(iii) material type and throughput; and

(iv) other actual parameters essential for accuracy for determining emissions and compliance with all applicable requirements of this section.

(C) The fee for this registration shall be \$75 for small businesses (as defined in §106.50 of this title) or \$400 for all others.

(7) Certified registrations or certifications are required in the following circumstances:

(A) For projects at existing major sites, establish emission increases less than any applicable threshold or contemporaneous emission increases for major sources or major modifications under prevention of significant deterioration (PSD), nonattainment new source review (NNSR) as specified in §116.12 of this title and in Federal Clean Air Act §112(g), §112(j), or the definition of major source in §122.10 of this title.

(B) If a project or registration includes control for reductions, limited hours, throughput, and materials or other operational limitations which are less than the potential to emit, and if modeling is used to demonstrate compliance with subsection (k) of this section.

(C) If a project is located at a site subject to NO_x cap and trade requirements in Chapter 101, Subchapter H of this title (relating to Emissions Banking and Trading) or relies on controls to comply with any state or federal regulation.

(D) For projects which resolve compliance issues and are the result of a commission or United States Environmental Protection Agency order.

(8) If the ePermits system is not available for more than 24 hours or not otherwise accessible, hard copies of notifications, registrations, or certifications may be submitted by first-class mail.

(9) If emissions increase at an OGS to a level where it exceeds its current authorization, either through a change in production or addition of facilities, the site may claim and register its facilities under the applicable authorization (Level 1 or Level 2 PBR or Standard Permit) as follows:

(A) Within 90 days from the initial notification of construction of an oil and gas facility, a registration can update the authorization mechanism by submitting a revision to the PBR or an application for a standard permit; and

(B) Within 90 days of the change of production or installation of additional equipment, a revision to the PBR or an application for a standard permit has been submitted.

(g) Level 1 Requirements. Total maximum estimated emissions shall meet the most stringent of the following. All emissions estimates must be based on representative worst-case operations and planned MSS activities.

(1) Emissions of any criteria air contaminant shall not exceed the applicable limits for a major stationary source or major modification for PSD, NNSR and in Federal Clean Air Act, §112(g), §112(j), or the definition of major source in §122.10 of this title.

(2) Emissions must meet the limitations established in subsection (k) of this section.

(3) Maximum emissions are limited to less than the following after any operator limitations or controls:

Figure: 30 TAC §106.352(g)(3) (No change to the figure as it currently exists in TAC.)

(h) Level 2 Requirements. If the requirements of Level 1 cannot be met, then the conditions of this subsection must be followed. Total maximum estimated registered or certified emissions shall meet the most stringent of the following. All emissions estimates must be based on representative worst-case operations and planned MSS activities.

(1) Total maximum estimated annual emissions of any air contaminant shall not exceed the applicable limits for a major stationary source or major modification for PSD and NNSR as specified in §116.12 of this title.

(2) Emissions must meet the limitations established in subsection (k) of this section.

(3) Maximum emissions are limited to less than the following after any operator limitations or controls:

Figure: 30 TAC §106.352(h)(3) (No change to the figure as it currently exists in TAC.)

(i) **Planned Maintenance, Startups and Shutdowns.** For any facility, group of facilities or site using this section or previous versions of this section, the following shall apply.

(1) Prior to January 5, 2012, representations and registration of planned MSS is voluntary, but if represented must meet the applicable limits of this section. After January 5, 2012, all emissions from planned MSS activities and facilities must be considered for compliance with applicable limits of this section. This section may not be used at a site or for facilities authorized under §116.111 of this title if planned MSS has already been authorized under that permit.

(2) As specified, releases of air contaminants during, or as result of, planned MSS must be quantified and meet the emission limits in this section, as applicable. This analysis must include:

(A) alternate operational scenarios or redirection of vent streams;

(B) pigging, purging, and blowdowns;

(C) temporary facilities if used for degassing or purging of tanks, vessels, or other facilities;

(D) degassing or purging of tanks, vessels, or other facilities; and

(E) management of sludge from pits, ponds, sumps, and water conveyances.

(3) Other planned MSS activities authorized by this section are limited to the following. These planned MSS activities require only recordkeeping of the activity.

(A) Routine engine component maintenance including filter changes, oxygen sensor replacements, compression checks, overhauls, lubricant changes, spark plug changes, and emission control system maintenance.

(B) Boiler refractory replacements and cleanings.

(C) Heater and heat exchanger cleanings.

(D) Turbine hot section swaps.

(E) Pressure relief valve testing, calibration of analytical equipment; instrumentation/analyzer maintenance; replacement of analyzer filters and screens.

(4) Engine/compressor startups associated with preventative system shutdown activities have the option to be authorized as part of typical operations if:

(A) prior to operation, alternative operating scenarios to divert gas or liquid streams are registered and certified with all supporting documentation;

(B) engine/compressor shutdowns shall result in no greater than 4 lb/hr of natural gas emissions; and

(C) emissions which result from the subsequent compressor startup activities are controlled to a minimum of 98% efficiency for VOC and H₂S.

(j) Records, sampling, and monitoring. The following records shall be maintained at a site in written or electronic form and be readily available to the agency or local air pollution control program with jurisdiction upon request. All required records must be kept at the facility site. If the facility normally operates unattended, records must be maintained at an office within Texas having day-to-day operational control of the plant site. Other requirements, including but not limited to, federal recordkeeping or testing requirements, can be used to demonstrate compliance if the other requirements are at least as stringent as the associated requirements in the Tables 7 and 8 in subsection (m)

of this section. Any documentation that is already being kept for other purposes will suffice for demonstrating requirements. If a control or method is not relied upon for emission reductions, then the associated sampling, monitoring, and records are not applicable.

(1) Sampling and demonstrations of compliance shall include the requirements listed in Table 7 in subsection (m) of this section.

(2) Monitoring and records for demonstrations of compliance shall include the requirements listed in Table 8 in subsection (m) of this section.

(k) Emission limits based on impacts evaluation.

(1) All impacts evaluations must be completed on a contaminant-by-contaminant basis for any net emissions increases resulting from a project and must meet the following as appropriate:

(A) Compliance with state or federal ambient air standards shall be demonstrated for nitrogen dioxide (NO₂), SO₂, and H₂S at any property-line within 1/4 mile or 1/2 mile of a project under subsection (g) (Level 1) or subsection (h) (Level 2) of this section, respectively.

(B) Compliance with hourly ESLs for benzene and annual ESL for benzene, shall be demonstrated at the nearest receptor within 1/4 mile or 1/2 mile of a project under subsection (g) (Level 1) or subsection (h) (Level 2) of this section, respectively.

(2) Distance measurements shall be determined using the following.

(A) For each facility or group of facilities, the shortest corresponding distance from any emission point, vent, or fugitive component to the nearest receptor must be used with the appropriate compliance determination method with the published ESLs as found through the TCEQ [commissioner's] internet Web page.

(B) For each facility or group of facilities, the shortest corresponding distance from any emission point, vent, or fugitive component to the nearest property line must be used with the appropriate compliance determination method with any applicable state or federal ambient air quality standard.

(3) Impacts evaluations are not required under the following cases:

(A) If there is no receptor within 1/4 mile of a Level 1 registration, or 1/2 mile of a Level 2 registration, no further ESL review is required.

(B) If there is no property line within 1/4 mile of a Level 1 registration, or 1/2 mile of a Level 2 registration, no further ambient air quality standard review is required.

(C) If the project total emissions are less than any of the following rates, no additional analysis or demonstration of the specified air contaminant is required:

Figure: 30 TAC §106.352(k)(3)(C) (No change to the figure as it currently exists in TAC.)

(4) Evaluation of emissions shall meet the following.

(A) For all evaluations of NO_x to NO_2 , a conversion factor of 0.20 for 4-stroke rich and lean-burn engines and 0.50 for 2-stroke lean-burn engines may be used.

(B) The maximum predicted concentration or rate at the property boundary or receptor, whichever is appropriate, must not exceed a state or federal ambient air standard or ESL.

(5) The impacts analysis shall be based on the following facility emissions.

(A) The following shall be met for ESL reviews:

(i) If a project's air contaminant maximum predicted concentrations are equal to or less than 10% of the appropriate ESL, no further review is required.

(ii) If a project's air contaminant maximum predicted concentrations combined with project increases for that contaminant over a 60-month period after the effective date of this revised section are equal to or less than 25% of the appropriate ESL, no further review is required.

(iii) In all other cases, all facility emissions at an OGS, regardless of authorization type, located within 1/4 mile of a project requiring registration under this section shall be evaluated.

(B) The following shall be met for state and federal ambient air quality standard reviews:

(i) If a project's air contaminant maximum predicted concentrations are equal to or less than the significant impact level (also known as *de minimis* impact in Chapter 101 of this title (relating to General Air Quality Rules)), no further review is required;

(ii) In all other cases, all facility emissions at an OGS, regardless of authorization type, located within 1/4 mile of a project requiring registration under this section shall be evaluated.

(6) Evaluation must comply with one of the methods listed with no changes or exceptions.

(A) Tables.

(i) Emission impact Tables 2 - 5F in subsection (m) of this section, may be used in accordance with the limits and descriptions in Table 1 in subsection (m) of this section.

(ii) Values in Tables 2 - 5F in subsection (m) of this section may be used with linear interpolation between height and distance points. A distance of less than 50 feet or greater than 5,500 feet may not be used. Release heights may not be extrapolated beyond the limits of any table and instead the minimum or maximum height will be used. If distances and release heights are not interpolated, the next lowest height and lesser distances shall be used for determination of maximum acceptable emissions. All facilities exempted from the distance to the property line restriction in subsection (e)(2) of this section must use 50 feet as the distance to the property line for those ambient standards based on property line.

(B) Screening Modeling. A screening model may be used to demonstrate acceptable emissions from an OGS under this section if all of the parameters in the screening modeling protocol provided by the commission are met.

(C) Dispersion Modeling. A refined dispersion model may be used to demonstrate acceptable emissions from an OGS under this section if all of the parameters in the refined dispersion modeling protocol provided by the commission are met.

(l) The requirements in this subsection are applicable to new and modified facilities except those specified in subsection (a)(1) of this section. Any oil or gas

production facility, carbon dioxide separation facility, or oil or gas pipeline facility consisting of one or more tanks, separators, dehydration units, free water knockouts, gunbarrels, heater treaters, natural gas liquids recovery units, or gas sweetening and other gas conditioning facilities, including sulfur recovery units at facilities conditioning produced gas containing less than two long tons per day of sulfur compounds as sulfur are permitted by rule, provided that the following conditions of this subsection are met. This subsection applies only to those facilities named which handle gases and liquids associated with the production, conditioning, processing, and pipeline transfer of fluids found in geologic formations beneath the earth's surface.

(1) Compressors and flares shall meet the requirements of §106.492 and §106.512 of this title (relating to Flares; and Stationary Engines and Turbines, respectively). Oil and gas facilities which are authorized under historical standard exemptions and remain unchanged maintain that authorization and the remainder of this subsection does not apply.

(2) Total emissions, including process fugitives, combustion unit stacks, separator, or other process vents, tank vents, and loading emissions from all such facilities constructed at a site under this subsection shall not exceed 25 tpy each of SO₂, all other sulfur compounds combined, or all VOCs combined; and 250 tpy each of NO_x

and CO. Emissions of VOC and sulfur compounds other than SO₂ must include gas lost by equilibrium flash as well as gas lost by conventional evaporation.

(3) Any facility handling sour gas shall be located at least one-quarter mile from any recreational area or residence or other structure not occupied or used solely by the owner or operator of the facility or the owner of the property upon which the facility is located.

(4) Total emissions of sulfur compounds, excluding sulfur oxides, from all vents shall not exceed 4.0 pounds per hour (lb/hr) and the height of each vent emitting sulfur compounds shall meet the following requirements, except in no case shall the height be less than 20 feet, where the total emission rate as H₂S, lb/hr, and minimum vent height (feet), and other values may be interpolated:

(A) 0.27 lb/hr at 20 feet;

(B) 0.60 lb/hr at 30 feet;

(C) 1.94 lb/hr at 50 feet;

(D) 3.00 lb/hr at 60 feet; and

(E) 4.00 lb/hr at 68 feet.

(5) Before operation begins, facilities handling sour gas shall be registered with the executive director [commission's Office of Permitting and Registration] in Austin using Form PI-7 along with supporting documentation that all requirements of this subsection will be met. For facilities constructed under §106.353 of this title (relating to Temporary Oil and Gas Facilities), the registration is required before operation under this subsection can begin. If the facilities cannot meet this subsection, a permit under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) is required prior to continuing operation of the facilities.

(m) The following tables shall be used as required in this section.

Figure: 30 TAC §106.352(m) (No change to the figure as it currently exists in TAC.)