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

Background and Summary of the Factual Basis for the Proposed Rule

On January 26, 2011, the commission adopted a new permit by rule (PBR), §106.352 which appeared in the February 18, 2011 issue of the *Texas Register* (36 *TexReg* 943), which extensively modified requirements for oil and gas facilities. This section had been under executive director review since 2006 to ensure that its conditions reflected current technology and were protective of human health. The commission had also determined that increased exploration, production, and transport of oil and natural gas in closer proximity to population concentrations warranted the new PBR. In order to fully develop its administration of the new section, the commission limited application of the newly promulgated subsections (a) - (k) to the Barnett Shale region of north central Texas which is composed 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.

Subsection (l) of the newly adopted PBR applies to oil and gas facilities in those counties of Texas outside the Barnett Shale region. Subsection (l) consists of the language and conditions that existed in §106.352 prior to the January 26, 2011, adoption. However, a paragraph of that language, which required oil and gas facilities handling sour gas to be located at least one-quarter mile from receptors was mistakenly omitted, and this proposal is intended to restore that paragraph.

Section Discussion

The commission proposes to add §106.352(l)(3) which states that 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. The subsequent paragraphs of subsection (l) would be re-numbered. This is not a new requirement but a restoration of the requirement that has existed in §106.352 since 1986 to the January 26, 2011 adoption. The intent of this requirement is to provide separation between wells producing hydrogen sulfide emission and structures and areas generally occupied by humans.

Additionally, the commission proposes a non-substantive change to correct a reference in Table 7 located in §106.352(m). The erroneous reference to Table 9 has been corrected to refer to Table 6.

Fiscal Note: Costs to State and Local Government

Jeff Horvath, Analyst, Strategic Planning and Assessment, has determined that, for the first five-year period the proposed rule is in effect, no fiscal implications are anticipated for the agency or other units of state or local governments as a result of the administration or enforcement of the proposed rule. The paragraph that would be added to §106.352(l) does not affect existing facilities, and would only apply to new or modified facilities outside the Barnett Shale region. This paragraph is not a new requirement and had been a requirement of §106.352 since 1986.

Public Benefits and Costs

Mr. Horvath 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 continued protection of public health and welfare because wells producing hydrogen sulfide emissions will be located a minimum distance from residences, buildings, institutions, and other public areas typically occupied by humans.

No costs to business or individuals are anticipated as a result of the implementation of the proposed amendment. The executive director has examined the registration records for PBRs, and no registration for a facility has been received that would place the facility within one-quarter mile of a receptor. Implementation of this amendment will not cause an increase in costs for oil and gas owners and operators since planning for the minimum distance can occur prior to construction.

Small Business and Micro-Business Assessment

No adverse fiscal implications are anticipated for small or micro-businesses as a result of the proposed rule. The proposed paragraph in subsection (l) was a previously existing requirement and applies only to new or modified facilities.

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 amendment is required to protect human health and the environment and 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. The proposed paragraph in subsection (l) was a previously existing requirement and applies only to new or modified facilities.

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 rulemaking in light of the regulatory impact analysis requirements of Texas Government Code, §2001.0225, and determined that the rulemaking does not meet the definition of a major environmental rule as defined in that statute, and in addition, if it did meet the definition, would not be subject to the requirement to prepare a regulatory impact analysis.

A major environmental rule means 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. The specific intent of proposed rule is to restore a paragraph to §106.352 that was mistakenly omitted. As discussed in the Fiscal Note portion of this preamble, the proposed rule is not anticipated to add any significant additional costs to affected individuals or businesses beyond what is already required to comply with these federal standards on 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.

Additionally, the rulemaking does not meet any of the four applicability criteria for requiring a regulatory impact analysis for a major environmental rule, which are listed in Texas Government Code, §2001.0225(a). Texas Government Code, §2001.0225, applies only to a major environmental rule, the result of which is to: 1) exceed a standard set by federal law, unless the rule is specifically required by state law; 2) exceed an express requirement of state law, unless the rule is specifically required by federal law; 3) exceed 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) adopt a rule solely under the general powers of the agency instead of under a specific state law.

The proposed rule implements requirements of the Federal Clean Air Act. The proposed amendment is based on federal requirements for a permitting program and is necessary for federal approval of the Texas State Implementation Plan. The proposed rule does not exceed a requirement of a delegation agreement or a contract between state and federal government if this rulemaking is adopted. The amendment was not developed solely under the general powers of the agency, but is authorized by specific sections of Texas Health and Safety Code (THSC), Chapter 382 (also known as the Texas Clean Air Act (TCAA)), and the Texas Water Code, which are cited in the Statutory Authority section of this preamble, including THSC, §382.05196 and §382.051963.

In addition, Senate Bill 1134, Section 3 of the 82nd Legislature, 2011, specifically permits the commission to amend this PBR to require the distance limitation for sour sites without the necessity of completing a regulatory impact assessment.

Therefore, this proposed rulemaking action is not subject to the regulatory analysis provisions of Texas Government Code, §2001.0225(b). Comments on this draft determination may be submitted to the contact person at the address listed under the Submittal of Comments portion of this preamble.

Takings Impact Assessment

Under Texas Government Code, §2007.002(5), taking means 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 §17 or §19, Article I, Texas Constitution; or a governmental action that 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 is the producing cause of a reduction of at least 25% 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.

The commission completed a takings impact analysis for the proposed rulemaking action under the Texas Government Code, §2007.043. The primary purpose of this proposed rulemaking action, as discussed elsewhere in this preamble, is to restore a paragraph mistakenly omitted from §106.352. The proposed rule will not create any additional burden on private real property. The proposed rule will not affect private real property in a manner that would require compensation to private real property owners under the United States Constitution or the Texas Constitution. The proposal also will not affect private real property in a manner that restricts or limits an owner's right to the property that would otherwise exist in the absence of the governmental action. Therefore, the proposed rulemaking will not cause 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 Chapter 281, Subchapter B. As required by §281.45(a)(3) and 31 TAC §505.11(b)(2), 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(1)). The proposed amendment will benefit the environment by ensuring that oil and gas facilities producing hydrogen sulfide emissions are located a minimum distance from receptors. The CMP policy applicable to this rulemaking action is the policy that commission rules comply with federal regulations in

40 Code of Federal Regulations, 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 the proposed 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 Chapter 122. 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 in Austin on October 3, 2011 at 2:00 p.m. in Building E, Room 201S 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 Michael Parrish, 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 2011-014-106-PR. The comment period closes October 3, 2011. 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 Blake Stewart, Air Permits Division, (512) 239-6931.

SUBCHAPTER O: OIL AND GAS

§106.352

Statutory Authority

The amended section 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, §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purposes of the Texas Clean Air Act. The amended section is also proposed under Texas Health and Safety Code, §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; and §382.057, concerning Exemption, which authorizes exemptions from permitting.

The amended section implements Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.017, 382.051, 382.05196, and 382.057. This amended section also implements Texas Health and Safety Code, §382.051963, as adopted by the 82nd Legislature, 2011.

§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 8 hours a day, 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 (PM_{10}); 10 tpy of particulate matter less than 2.5 microns ($PM_{2.5}$); and 25 tpy of volatile organic compounds (VOC), sulfur dioxide (SO_2), hydrogen sulfide (H_2S), 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 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 H_2S 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 H_2S 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 H_2S;

(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) H_2S; or

(iii) up to 20 hp fueled by sour gas containing more than 10,000 ppmw but not more than 50,000 ppmw H_2S.

(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; or

(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, H_2S 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 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 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, H_2S, 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 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 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 H_2S are allowed up to a potential to emit equal to 1.0 tpy of VOC and 0.1 tpy of H_2S.

(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 H_2S 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 at 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 H_2S 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 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 NOX 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)

(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)

(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 H_2S.

(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 (NO_2), SO_2, and H_2S 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 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)

(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 SO_2 , 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 SO_2 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) [(3)] 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 H_2S, 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) [(4)] Before operation begins, facilities handling sour gas shall be registered with the 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)

[Figure: 30 TAC §106.352 (m)]

Table 1 Emission Impact Tables Limits and Descriptions

Topic	Description	Details
Variables	$E_{MAX\ HOURLY}$	the maximum acceptable hourly (lb/hr) emissions for a specific air contaminant
	$E_{MAX\ ANNUAL}$	the maximum acceptable annual (tpy) emissions for a specific air contaminant
	P	ambient air standard for a specific air contaminant (µg/m^3)
	ESL	current published effects screening level for a specific air contaminant (µg/m^3)
	G	the most stringent of any applicable generic value from the Generic Modeling Results Tables at the emission point's release height and distance to property line (µg/m^3/lb/hr)
	WR_{EPNx}=	weighted ratio of emissions of a specific air contaminant for each EPN divided by the sum of total emissions for all EPNs that emit that contaminant or (E_{EPNx}/E_{total})
Single releases or co-located groups of similar releases	hourly ambient air standard	emissions are determined by: $\boldsymbol{E_{MAX\ HOURLY} = P/G}$
	hourly health effects review	emissions are determined by: $\boldsymbol{E_{MAX\ HOURLY} = ESL/G}$
	annual ambient air standard	emissions are determined by: $\boldsymbol{E_{MAX\ ANNUAL} = (8760/2000)\ P/(0.08*G)}$
	annual health effects review	emissions are determined by: $\boldsymbol{E_{MAX\ ANNUAL} = (8760/2000)\ ESL/(0.08*G)}$
Multiple release points	Limits	If weighted ratios are not used, the total quantity of emissions shall be assumed to be released from the most conservative applicable G value at the site.
	hourly ambient air standard	emissions are determined by: $\boldsymbol{E_{MAX\ HOURLY} = (WR_{EPN1})\ (P / G_{EPN1}) + (WR_{EPN2})\ (P / G_{EPN2}) + \ldots(WR_{EPNx})\ (P / G_{EPNx})}$
	hourly health effects review	emissions are determined by: $\boldsymbol{E_{MAX\ HOURLY} = (WR_{EPN1})\ (ESL / G_{EPN1}) + (WR_{EPN2})\ (ESL/G_{EPN2}) + \ldots..(WR_{EPNx})\ (ESL / G_{EPNx})}$
	annual ambient air standard	emissions are determined by: $\boldsymbol{E_{MAX\ ANNUAL} = (8760/2000)\ ((WR_{EPN1})\ (P / 0.08*G_{EPN1}) + (WR_{EPN2})\ (P / 0.08*G_{EPN2}) + \ldots.\ (WR_{EPNx})\ (P}$

		/ 0.08*G_{EPNx}))
	annual health effects review	emissions are determined by: ***$E_{MAX\ ANNUAL}$ = (8760/2000) ((WR_{EPN1}) (ESL /0.08*G_{EPN1}) + (WR_{EPN2}) (ESL/0.08*G_{EPN2}) + ...(WR_{EPNx}) (ESL / 0.08*G_{EPNx}))***

Table 2. Generic Modeling Results for Fugitives & Process Vents

Distance	Fugitive - 3ft	Loading -10 ft	Tank Hatch - 20 ft	Process Vessel 10 ft Vent	Process Vessel 20 ft Vent	Process Vessel 30 ft Vent	Process Vessel 40 ft Vent	Process Vessel 50 ft Vent	Process Vessel 60 ft Vent
(feet)	(µg/m³)/(lb/hr)	(µg/m³)/(lb/hr)	(µg/m³)/(lb/hr)	(µg/m³)/(lb/hr)	(µg/m³)/(lb/hr)	(µg/m³)/(lb/hr)	(µg/m³)/(lb/hr)	(µg/m³)/(lb/hr)	(µg/m³)/(lb/hr)
50	4375	1232	305	469	168	90	70	65	28
100	4375	1232	305	469	168	90	70	65	28
150	3907	1232	305	469	168	90	70	65	28
200	3089	1232	305	440	168	90	70	65	28
300	1911	1193	294	412	168	90	70	65	28
400	1269	1048	291	319	168	90	70	65	28
500	901	858	274	243	157	90	70	65	28
600	674	698	267	189	138	89	70	65	28
700	525	574	271	150	120	88	70	65	28
800	423	479	261	124	105	85	70	65	28
900	349	406	244	105	93	81	70	65	28
1000	293	348	226	91	84	77	69	65	26
1100	250	302	208	90	77	72	67	63	25
1200	217	264	191	89	70	68	64	61	24
1300	189	233	176	88	65	64	61	58	24
1400	167	208	161	87	61	60	58	55	24
1500	149	186	149	84	57	57	55	53	24
1600	134	168	137	82	54	53	52	50	23
1700	121	153	127	79	51	51	49	47	23
1800	110	139	117	76	50	48	47	45	22
1900	100	128	109	73	49	46	44	43	22
2000	92	117	102	70	49	44	42	41	21
2100	85	108	95	67	48	42	41	39	21
2200	78	101	89	64	47	40	39	38	20
2300	73	94	83	61	46	39	37	36	19
2400	68	88	78	59	45	37	36	35	19

2500	64	82	74	56	43	36	35	34	18
2600	60	77	70	54	42	34	33	32	18
2700	56	73	66	52	41	33	32	31	17
2800	53	69	63	50	40	32	31	30	17
2900	50	65	60	48	39	31	30	29	16
3000	48	62	57	46	37	30	29	28	16
3500	37	49	46	38	32	26	25	25	14
4000	30	40	38	32	28	24	23	22	12
4500	25	33	32	28	25	21	20	20	11
5000	22	28	27	24	22	19	18	18	10
5500	19	25	24	21	19	17	17	16	9

Table 3: Flares and Thermal Destruction Devices					
Generic Modeling Results					
Distance	20 ft height	30 ft height	40 ft height	50 ft height	60 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
50	58	43	26	25	23
100	58	43	26	25	23
150	58	43	26	25	23
200	58	43	26	25	23
300	58	43	26	25	23
400	58	43	26	25	23
500	58	43	26	25	23
600	56	43	26	25	23
700	52	43	26	25	23
800	47	43	26	25	23
900	45	43	26	25	23
1000	44	43	26	25	23
1100	42	41	25	24	23
1200	40	40	24	24	22
1300	38	38	23	23	21
1400	36	36	23	21	21
1500	34	34	23	21	20
1600	32	32	22	21	20
1700	31	31	22	21	20
1800	29	29	22	20	20
1900	28	28	22	20	20
2000	26	26	21	20	19
2100	25	25	21	20	19
2200	24	24	20	20	19
2300	23	23	20	19	19
2400	22	22	20	19	18
2500	22	22	19	18	18
2600	21	21	19	18	17
2700	20	20	18	17	17
2800	19	19	18	17	16
2900	19	19	17	16	16
3000	18	18	17	16	16

3500	16	16	15	14	14
4000	14	14	13	12	12
4500	13	13	12	11	11
5000	11	11	11	10	10
5500	11	11	10	9	9

Table 4: Generic Modeling Results for Blowdowns, Purging, and Pigging					
	Generic Modeling Results				
Distance	< 30 psig; 3 ft height	< 30 psig; 10 ft height	< 30 psig; 20 ft height	≥ 30 psig; 6 ft height	≥ 30 psig; 10 ft height
(ft)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)	G_{hourly} (μg/m³)/(lb/hr)
50	4304	791	244	51	25
100	4304	791	244	51	25
150	4250	777	244	51	25
200	3621	763	244	51	25
300	2367	750	225	51	25
400	1607	737	225	51	25
500	1156	671	224	51	25
600	871	581	218	48	25
700	682	498	212	44	25
800	551	427	210	40	24
900	456	368	204	36	23
1000	384	320	194	33	21
1100	328	281	182	30	20
1200	284	248	170	28	18
1300	249	221	159	27	17
1400	220	198	147	27	16
1500	196	178	137	27	15
1600	176	162	127	27	14
1700	159	147	118	27	13
1800	145	135	110	27	13
1900	132	124	103	27	13
2000	121	114	96	27	13
2100	112	106	90	27	13
2200	103	98	85	27	13
2300	96	91	80	27	13
2400	90	86	75	27	13
2500	84	81	71	27	13
2600	79	76	68	27	13
2700	74	72	64	26	13
2800	70	68	61	26	13
2900	67	64	58	26	13

3000	63	61	55	25	13
3500	50	48	45	23	13
4000	40	39	37	21	13
4500	34	33	31	19	13
5000	29	28	27	17	12
5500	25	24	23	16	11

Table 5A Engines Less Than or Equal to 250 hp											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
50	97	85	83	81	81	71	58	44	43	36	26
100	97	85	83	81	81	71	58	44	43	36	26
150	97	85	83	81	81	71	58	44	43	36	26
200	93	85	83	81	81	71	58	44	43	36	26
300	92	85	83	81	81	71	58	44	43	36	26
400	91	85	83	81	81	71	58	44	43	36	26
500	88	85	83	81	81	71	58	44	43	36	26
600	80	79	78	78	78	70	56	44	43	36	26
700	78	77	76	76	71	68	52	44	43	36	26
800	76	75	74	74	64	63	47	44	43	36	26
900	74	73	72	72	58	58	45	44	43	36	26
1000	72	71	71	71	53	53	44	43	43	36	26
1100	69	69	69	69	49	49	42	42	41	35	25
1200	66	66	66	65	45	45	40	40	40	35	24
1300	62	62	62	62	42	42	38	38	38	33	23
1400	59	59	59	59	39	39	36	36	36	32	23

1500	56	56	56	56	37	37	34	34	34	30	23
1600	53	53	53	53	35	35	32	32	32	29	22
1700	50	50	50	50	33	33	31	31	31	28	22
1800	48	48	48	48	31	31	29	29	29	26	22
1900	46	46	46	46	30	30	28	28	28	25	22
2000	44	44	44	44	28	28	26	26	26	24	21
2100	42	42	42	42	27	27	25	25	25	23	21
2200	40	40	40	40	26	26	24	24	24	22	20
2300	38	38	38	38	25	25	23	23	23	21	20
2400	37	37	37	37	24	24	22	22	22	20	20
2500	36	36	36	36	23	23	22	22	22	20	19
2600	34	34	34	34	22	22	21	21	21	19	19
2700	33	33	33	33	21	21	20	20	20	18	18
2800	32	32	32	32	21	21	19	19	19	18	18
2900	31	31	31	31	20	20	19	19	19	17	17
3000	30	30	30	30	19	19	18	18	18	17	17
3500	26	26	26	26	17	17	16	16	16	15	15
4000	23	23	23	23	15	15	14	14	14	13	13
4500	21	21	21	21	13	13	13	13	13	12	12
5000	19	19	19	19	12	12	11	11	11	11	11
5500	17	17	17	17	11	11	11	11	11	10	10

Table 5B: Engines Greater Than 250 and Less Than or Equal to 500 hp

Generic Modeling Results

Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
50	60	59	54	43	43	34	34	24	21	20	17
100	60	59	54	43	43	34	34	24	21	20	17
150	60	59	54	43	43	34	34	24	21	20	17
200	60	59	54	43	43	34	34	24	21	20	17
300	60	59	54	43	43	34	34	24	21	20	17
400	60	59	54	43	43	34	34	24	21	20	17
500	60	59	54	43	43	34	34	24	21	20	17
600	57	57	52	41	41	34	34	24	21	20	17
700	52	52	47	38	38	31	31	24	21	20	17
800	47	47	43	34	34	28	28	24	21	20	17
900	42	42	39	31	31	26	26	23	20	20	17
1000	39	39	35	28	28	23	23	21	20	20	17
1100	37	36	32	26	26	23	23	20	20	19	17
1200	35	35	30	25	24	23	23	20	20	18	17
1300	34	34	28	24	23	23	23	20	20	18	16
1400	32	32	26	24	23	23	23	20	20	17	16
1500	31	31	24	23	23	23	23	20	20	16	16
1600	29	29	23	23	23	23	23	19	19	16	16
1700	28	28	23	23	23	23	22	19	19	16	15

1800	27	27	22	22	22	22	22	19	19	16	15
1900	25	25	22	22	22	21	21	18	18	16	15
2000	24	24	22	22	22	21	21	17	17	16	15
2100	23	23	21	21	21	20	20	17	17	16	15
2200	22	22	21	21	21	19	19	17	17	15	15
2300	21	21	20	20	20	19	19	17	16	15	14
2400	21	21	20	20	20	19	18	16	16	15	14
2500	20	20	19	19	19	18	18	16	16	14	14
2600	19	19	19	19	19	18	17	16	16	14	13
2700	18	18	18	18	18	17	17	15	15	14	13
2800	18	18	18	18	18	17	16	15	15	13	13
2900	17	17	17	17	17	16	16	15	15	13	13
3000	17	17	17	17	17	16	15	15	15	13	13
3500	15	15	15	15	15	14	14	13	13	12	11
4000	13	13	13	13	13	13	12	12	12	11	10
4500	12	12	12	12	12	11	11	10	10	10	9
5000	11	11	11	11	11	10	10	10	10	9	9
5500	10	10	10	10	10	9	9	9	9	8	8

Table 5C: Engines Greater Than 500 and Less Than or Equal to 1,000 hp											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
50	26	25	25	25	18	18	17	13	11	11	10
100	26	25	25	25	18	18	17	13	11	11	10
150	26	25	25	25	18	18	17	13	11	11	10
200	26	25	25	25	18	18	17	13	11	11	10
300	26	25	25	25	18	18	17	13	11	11	10
400	26	25	25	25	18	18	17	13	11	11	10
500	26	25	25	25	18	18	17	13	11	11	10
600	26	25	25	25	18	18	17	13	11	11	10
700	26	25	25	25	18	18	17	13	11	11	10
800	24	24	24	24	18	18	17	13	11	11	10
900	23	23	23	23	18	18	17	13	11	11	10
1000	21	21	21	21	17	17	17	13	11	11	10
1100	20	20	20	20	17	17	16	13	11	11	10
1200	18	18	18	18	16	16	16	12	11	11	10
1300	17	17	17	17	15	15	15	12	11	10	10
1400	17	17	17	17	14	14	14	11	11	10	10
1500	17	17	16	16	13	13	13	11	11	10	9
1600	17	17	16	16	13	13	13	11	11	10	9
1700	16	16	15	15	13	12	12	11	11	9	9

1800	16	16	15	15	13	12	12	11	11	9	9
1900	15	15	14	14	13	12	12	11	10	9	9
2000	15	15	14	14	13	12	12	11	10	9	9
2100	14	14	13	13	12	12	12	11	10	9	9
2200	14	14	13	13	12	12	12	10	10	9	9
2300	13	13	12	12	12	11	11	10	10	9	8
2400	13	13	12	12	12	11	11	10	9	9	8
2500	12	12	12	12	11	11	11	10	9	9	8
2600	12	12	11	11	11	11	11	10	9	9	8
2700	12	12	11	11	11	10	10	10	9	8	8
2800	11	11	11	11	11	10	10	9	9	8	8
2900	11	11	10	10	10	10	10	9	9	8	8
3000	11	11	10	10	10	10	10	9	9	8	8
3500	9	9	9	9	9	9	9	8	8	7	7
4000	8	8	8	8	8	8	8	7	7	7	6
4500	7	7	7	7	7	7	7	7	6	6	6
5000	7	7	7	7	6	6	6	6	6	6	5
5500	6	6	6	6	6	6	6	6	5	5	5

Table 5D: Engines Greater Than 1,000 and Less Than or Equal to 1,500 hp

Generic Modeling Results

Distance (ft)	8 ft height G_{hourly} (µg/m³)/(lb/hr)	10 ft height G_{hourly} (µg/m³)/(lb/hr)	12 ft height G_{hourly} (µg/m³)/(lb/hr)	14 ft height G_{hourly} (µg/m³)/(lb/hr)	16 ft height G_{hourly} (µg/m³)/(lb/hr)	18 ft height G_{hourly} (µg/m³)/(lb/hr)	20 ft height G_{hourly} (µg/m³)/(lb/hr)	25 ft height G_{hourly} (µg/m³)/(lb/hr)	30 ft height G_{hourly} (µg/m³)/(lb/hr)	35 ft height G_{hourly} (µg/m³)/(lb/hr)	40 ft height G_{hourly} (µg/m³)/(lb/hr)
50	17	13	12	10	10	10	10	9	8	8	7
100	17	13	12	10	10	10	10	9	8	8	7
150	17	13	12	10	10	10	10	9	8	8	7
200	17	13	12	10	10	10	10	9	8	8	7
300	17	13	12	10	10	10	10	9	8	8	7
400	17	13	11	10	10	10	10	9	8	8	7
500	17	13	11	10	10	10	10	9	8	8	7
600	17	12	11	10	10	10	10	9	8	8	7
700	17	11	11	10	10	10	10	9	8	8	7
800	17	11	11	10	10	10	10	9	8	8	7
900	17	11	11	10	10	10	10	9	8	8	7
1000	17	11	11	10	10	10	10	9	8	8	7
1100	16	11	11	10	10	10	10	9	8	8	7
1200	15	10	10	10	9	9	9	9	8	7	7
1300	15	10	10	10	9	9	9	8	8	7	7
1400	14	10	10	10	9	9	8	8	8	7	7
1500	13	10	10	10	8	8	8	8	8	7	6
1600	12	10	10	10	8	8	8	8	8	7	6
1700	12	10	10	10	8	8	8	8	8	7	6

1800	11	10	10	10	8	8	8	8	8	7	6
1900	11	10	9	9	8	8	8	7	7	7	6
2000	10	9	9	9	8	8	8	7	7	7	6
2100	10	9	9	9	8	8	8	7	7	6	6
2200	10	9	9	9	8	8	8	7	7	6	6
2300	9	9	8	8	8	8	8	7	7	6	6
2400	9	9	8	8	7	7	7	7	7	6	6
2500	9	8	8	8	7	7	7	7	6	6	5
2600	8	8	8	8	7	7	7	7	6	6	5
2700	8	8	8	8	7	7	7	7	6	6	5
2800	8	8	7	7	7	7	7	6	6	6	5
2900	8	7	7	7	7	7	7	6	6	6	5
3000	7	7	7	7	7	7	6	6	6	5	5
3500	7	6	6	6	6	6	6	6	5	5	5
4000	6	6	6	6	5	5	5	5	5	4	4
4500	5	5	5	5	5	5	5	5	4	4	4
5000	5	5	5	5	5	5	4	4	4	4	4
5500	5	4	4	4	4	4	4	4	4	4	3

Table 5E: Engines Greater Than 1,500 and Less Than or Equal to 2,000 hp

Generic Modeling Results

Distance (ft)	8 ft height G_{hourly} (µg/m³)/(lb/hr)	10 ft height G_{hourly} (µg/m³)/(lb/hr)	12 ft height G_{hourly} (µg/m³)/(lb/hr)	14 ft height G_{hourly} (µg/m³)/(lb/hr)	16 ft height G_{hourly} (µg/m³)/(lb/hr)	18 ft height G_{hourly} (µg/m³)/(lb/hr)	20 ft height G_{hourly} (µg/m³)/(lb/hr)	25 ft height G_{hourly} (µg/m³)/(lb/hr)	30 ft height G_{hourly} (µg/m³)/(lb/hr)	35 ft height G_{hourly} (µg/m³)/(lb/hr)	40 ft height G_{hourly} (µg/m³)/(lb/hr)
50	10	9	8	8	8	7	7	7	6	5	5
100	10	9	8	8	8	7	7	7	6	5	5
150	10	9	8	8	8	7	7	7	6	5	5
200	10	9	8	8	8	7	7	7	6	5	5
300	10	9	8	8	8	7	7	7	6	5	5
400	10	9	8	8	8	7	7	7	6	5	5
500	10	9	8	8	8	7	7	7	6	5	5
600	10	9	8	8	8	7	7	7	6	5	5
700	9	8	8	8	8	7	7	7	6	5	5
800	9	8	8	8	8	7	7	7	6	5	5
900	9	8	8	8	8	7	7	7	6	5	5
1000	9	8	8	8	8	7	7	7	6	5	5
1100	9	8	8	8	8	7	7	7	6	5	5
1200	8	8	7	7	7	7	7	7	6	5	5
1300	8	8	7	7	7	7	7	6	6	5	5
1400	8	8	7	7	7	7	7	6	6	5	5
1500	8	8	7	7	7	7	7	6	5	5	5
1600	8	8	7	7	7	7	7	6	5	5	5
1700	8	8	7	7	7	7	7	6	5	5	5

1800	8	8	7	7	7	7	7	6	5	5	5
1900	7	7	7	7	7	7	6	6	5	5	5
2000	7	7	7	7	7	7	6	6	5	5	5
2100	7	7	6	6	6	6	6	6	5	5	5
2200	7	7	6	6	6	6	6	6	5	5	4
2300	7	7	6	6	6	6	6	6	5	5	4
2400	7	7	6	6	6	6	6	5	5	5	4
2500	6	6	6	6	6	6	6	5	5	4	4
2600	6	6	6	6	6	6	5	5	5	4	4
2700	6	6	6	6	6	5	5	5	5	4	4
2800	6	6	6	6	5	5	5	5	4	4	4
2900	6	6	5	5	5	5	5	5	4	4	4
3000	6	5	5	5	5	5	5	5	4	4	4
3500	5	5	5	5	5	4	4	4	4	4	3
4000	4	4	4	4	4	4	4	4	4	3	3
4500	4	4	4	4	4	4	4	3	3	3	3
5000	4	4	4	3	3	3	3	3	3	3	3
5500	3	3	3	3	3	3	3	3	3	3	3

Table 5F: Engines Greater Than 2,000 hp											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
50	7	6	6	6	5	5	5	5	4	4	4
100	7	6	6	6	5	5	5	5	4	4	4
150	7	6	6	6	5	5	5	5	4	4	4
200	7	6	6	6	5	5	5	5	4	4	4
300	7	6	6	6	5	5	5	5	4	4	4
400	7	6	6	6	5	5	5	5	4	4	4
500	7	6	6	6	5	5	5	5	4	4	4
600	7	6	6	6	5	5	5	5	4	4	4
700	7	6	6	6	5	5	5	5	4	4	4
800	6	6	6	6	5	5	5	5	4	4	4
900	6	6	6	6	5	5	5	5	4	4	4
1000	6	6	6	6	5	5	5	5	4	4	4
1100	6	6	6	6	5	5	5	5	4	4	4
1200	6	6	6	6	5	5	5	5	4	4	4
1300	6	6	6	6	5	5	5	5	4	4	4
1400	6	6	6	6	5	5	5	5	4	4	4
1500	6	6	6	6	5	5	5	5	4	4	4
1600	6	6	6	6	5	5	5	5	4	4	4
1700	6	6	6	6	5	5	5	5	4	4	4

1800	6	6	6	6	5	5	5	5	4	4	4
1900	6	6	6	5	5	5	5	5	4	4	4
2000	6	6	6	5	5	5	5	5	4	4	3
2100	5	5	5	5	5	5	5	5	4	4	3
2200	5	5	5	5	5	5	5	4	4	4	3
2300	5	5	5	5	5	5	4	4	4	4	3
2400	5	5	5	5	5	5	4	4	4	4	3
2500	5	5	5	5	4	4	4	4	4	4	3
2600	5	5	5	5	4	4	4	4	4	3	3
2700	5	5	5	5	4	4	4	4	4	3	3
2800	5	5	5	4	4	4	4	4	4	3	3
2900	4	4	4	4	4	4	4	4	4	3	3
3000	4	4	4	4	4	4	4	4	3	3	3
3500	4	4	4	4	4	4	3	3	3	3	3
4000	3	3	3	3	3	3	3	3	3	3	3
4500	3	3	3	3	3	3	3	3	3	2	2
5000	3	3	3	3	3	3	3	2	2	2	2
5500	3	3	3	3	3	2	2	2	2	2	2

Table 6: Engine and Turbine Emission and Operational Standards

Engine Type	Engine Size	Manufacture Date	NO_X (g/bhp-hr)	CO (g/bhp-hr)	VOC (g/bhp-hr)
Rich-burn, Non-emergency, Spark-ignited	less than 500 hp	All dates	no standard	no standard	no standard
	greater than or equal to 500 hp	Before January 1, 2011	2	3	no standard
	greater than or equal to 500 hp	On or after January 1, 2011	1	3	1
	After January 1, 2020 and regardless of manufacture date, no rich-burn engine greater than or equal to 500 hp authorized by this rule shall emit NO_X in excess of 1.0 g/bhp-hr. The commission reserves the right to re-evaluate the upgrade requirement if EPA promulgates any standards for existing engines.				
Lean-burn, 2SLB, Non-emergency, Spark-ignited	less than 500 hp	All dates	no standard	no standard	no standard
	greater than or equal to 500 hp	Before September 23, 1982	8	3	no standard
		Before June 18, 1992 and rated less than 825 hp	8	3	no standard
		On or after September 23, 1982, but prior to June 18, 1992 and rated 825 hp or greater	5	3	no standard
		On or after June 18, 1992 but prior to July 1, 2010	2.0 except under reduced speed, 80-100% of full torque conditions may be 5.0	3	no standard
		On or after July	1	3	1

		1, 2010			
Lean-burn, 4SLB, Non-emergency, Spark-ignited, and Dual-fuel	less than 500 hp	Before July 1, 2008	no standard	no standard	no standard
		On or after July 1, 2008	2	3	1
	greater than or equal to 500 hp	Before September 23, 1982	5.0 except under reduced speed, 80-100% of full torque conditions may be 8.0	3	no standard
		Before June 18, 1992 and rated less than 825 hp	5.0 except under reduced speed, 80-100% of full torque conditions may be 8.0	3	no standard
		On or after September 23, 1982, but prior to June 18, 1992 and rated 825 hp or greater	5	3	no standard
		On or after June 18, 1992 but prior to July 1, 2010	2.0 except under reduced speed, 80-100% of full torque conditions, may be 5.0	3	no standard
		On or after July 1, 2010	1	3	1
	After January 1, 2030 and regardless of manufacture, no 4-stroke lean-burn engines authorized by this rule shall emit NO_X in excess of 2.0 grams per brake horsepower per hour (g/bhp-hr). The commission reserves the right to re-evaluate the upgrade requirement if EPA promulgates any standards for existing engines.				
Turbines	Turbines shall not emit greater than 25 ppmvd @15% NOx and 50 ppmvd @15% O2 for CO.				

Table 7: Sampling and Demonstrations of Compliance

Category	Description	Specifications and Expectations
Exclusions	Control Systems	Control device monitoring and records are required only where the device is necessary for the site to meet emission rate limits
Sampling General	When Applicable Ports & Platforms, Methods, Notifications and Timing	(A)If necessary, sampling ports and platforms shall be incorporated into the design of all exhaust stacks according to the specifications set forth in "Chapter 2, Stack Sampling Facilities." Engines and other facilities which are physically incapable of having platforms are excluded from this requirement. For control devices with effectiveness requirements only, appropriate sampling ports shall also be installed upstream of the inlet to control devices or controlled recovery systems with control efficiency requirements. Alternate sampling facility designs may be submitted for written approval by the Texas Commission on Environmental Quality (TCEQ) Regional Director or his designee. (B) Where stack testing is required, Sampling shall be conducted within 180 days of the change that required the registration, in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and in accordance with the appropriate EPA Reference Methods. Unless otherwise specified, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. Where appropriate, sampling shall occur as three one-hour test runs and then averaged to demonstrate compliance with the limits of this authorization. Any deviations from those procedures must be approved in writing by the TCEQ Regional Director or his designee prior to sampling. (C) The Regional Office shall be afforded the opportunity to observe all such sampling. (D) The holder of this authorization is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense.

		(E) The TCEQ Regional Office that has jurisdiction over the site shall be contacted as soon as any testing is scheduled, but not less than 30 days prior to sampling. The region shall have discretion to amend the 30 day prior notification. Except for engine testing and liquid/gas analysis sampling, all other sampling shall include an opportunity for the appropriate regional office to schedule a pretest meeting. The notice shall include: (i) Date for pretest meeting, if required; (ii)Date sampling will occur; (iii) Name of firm conducting sampling; (iv)Type of sampling equipment to be used; (v) Method or procedure to be used in sampling; (vi)Procedure used to determine operating rates or other relevant parameters during the sampling period; (vii) parameters to be documented during the sampling event; (viii) any proposed deviations to the prescribed sampling methods. If held, the purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for submitting the test reports. (F) Within 60 days after the completion of the testing and sampling required herein, one original and one copy of the sampling reports shall be sent to the Regional Office. (G) When sampling is required, all Quality Assurance/Quality Control shall follow 30 TAC Ch 25 National Environmental Laboratory Accreditation Conference accreditation requirements.
Fugitive monitoring and LDAR	Analyzers	An approved gas analyzer or other approved detection monitoring device used for the volatile organic compound fugitive inspection and repair requirement is a device that conforms to the requirements listed in Title 40 CFR '60.485(a) and (b), or is otherwise approved by the Environmental Protection Agency as a device to monitor for VOC fugitive emission leaks. Approved gas analyzers shall conform to requirements listed in Method 21 of 40 CFR Part 60, Appendix A. The gas analyzer shall be calibrated with methane. In addition, the

		response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section 8 of Method 21. If a mixture of VOCs is being monitored, the response factor shall be calculated for the average composition of the process fluid. If a response factor less than 10 cannot be achieved using methane, then the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured. In lieu of using a hydrocarbon gas analyzer and EPA Method 21, the owner or operator may use the Alternative Work Practice in 40 CFR Part 60, §60.18(g) - (i). The optical gas imaging instrument must meet all requirements specified in 40 CFR §60.18(g) - (i), except the annual Test Method 21 requirement in 40 CFR §60.18(h)(7) and the reporting requirement in 40 CFR §60.18(i)(5) do not apply.
Verify composition of materials	All site-specific gas or liquid analyses	Reports necessary to verify composition (including hydrogen sulfide (H_2S) at any point in the process. All analyses shall be site specific or a representative sample may be used to estimate emissions if all of the parameters in the gas and liquid analysis protocol provided by the commission are met. An analysis shall be performed within 90 or 180 days of initial start of operation or implementation of a change which requires registration. When new streams are added to the site and the character or composition of the streams change and cause an increase in authorized emissions, or upon request of the appropriate Regional office or local air pollution control program with jurisdiction, a new analysis will need to be performed. Analysis techniques may include, but are not limited to, Gas Chromatography (GC), Tutweiler, stain tube analysis, and sales oil/condensate reports. These records will document the following: (A) H_2S content; (B) flow rate; (C) heat content; or (D) other characteristic including, but not limited to: (i) American Petroleum Institute gravity and Reid vapor pressure (RVP);(ii) sales oil throughput; or

		(iii) condensate throughput. Laboratory extended VOC GC analysis at a minimum to C10+ and H_2S analysis for gas and liquids for the following shall be performed and used for emission compliance demonstrations: (A) Separator at the inlet; (B) Dehydration Unit / Glycol Contactor prior to dehydrator;(C) Amine Unit prior to sweetening unit; (D) Separator dumping to gunbarrel or storage tank; (E) Tanks for liquids and vapors; or (F) Produced Water or Brine/Salt Water at the inlet prior to storage.
Engines & Turbines	Initial Sampling of (i)Any engine greater than 500 horsepower; (ii) Any turbine	Perform stack sampling and other testing as required to establish the actual quantities of air contaminants being emitted into the atmosphere (including but not limited to nitrogen oxide (NO_X), carbon monoxide (CO), and oxygen (O_2). Each combustion facility shall be tested at a minimum of 50% of the design maximum firing rate of the facility. Each tested firing rate shall be identified in the sampling report. Sampling shall occur within 180 days after initial startup of each unit. Additional sampling shall occur as requested by the TCEQ Regional Director. If there are multiple engines at an oil and gas sites (OGS) of identical model, year, and control system, sampling may be performed on 50% of the units and used for compliance demonstration of all identical units at the OGS. The remaining 50% if the units not initially tested must be tested during the next biennial testing period. This sampling is not required upon initial installation at any location if the engine or turbine was previously installed and tested at any location in the United States and the test performed conformed with EPA Reference Methods. Regardless of engine location, records of performance testing, or relied upon sampling reports, must remain with each specific engine for a minimum of five years unless records are unavailable and the permit holder performs the initial sampling on-site. No one may claim records are unavailable for the time period in which an engine is at the site which is authorized by this section. This testing is not required for emergency

		engines unless requested by the TCEQ Regional Director. Idle engines do not need to be re-started only for the purpose of completing required testing. If biennial testing is required for an engine that is re-started for production purposes, the biennial testing is required within 30 days after re-starting the engine.
Engines	Periodic Evaluation	The following is applicable to sites with federal operating permits only: (A) For any engine with a NO_X standard under Table 6 [9]of this subsection, conduct evaluations of each engine performance semiannually after initial compliance testing by measuring the NO_X and CO content of the exhaust. Tests shall occur more than 90 days apart. Individual engines shall be subject to the semiannual performance evaluation if they were in operation for 2,000 hours or more during the six-month (semiannual) period. If an engine is not operating, the permit holder may delay the test until such time as the engine is expected to run for more than 14 days. Idled engines do not need to be re-started only for the purpose of completing required testing. (B) The use of portable analyzers specifically designed for measuring the concentration of each contaminant in parts per million by volume is acceptable for these evaluations. The portable analyzer shall be operated at minimum in accordance with the manufacturer's instructions. The operator may modify the procedure if it does not negatively alter the accuracy of the analyzer. Also, colorimetric testing (stain tubes) maybe used in these periodic evaluations. The NO_X and CO emissions then shall be converted into units of grams per horsepower-hour and pounds per hour. (C) Emissions shall be measured and recorded in the as-found operating condition, except no compliance determination shall be established during startup, shutdown, or under breakdown conditions (D) In lieu of the above mentioned periodic monitoring for engines and biennial testing, the holder of this permit may install, calibrate, maintain, and operate a continuous emission

		monitoring system (CEMS) to measure and record the concentrations of NO_X and CO from any engine, turbine, or other external combustion facility. Diluents to be measured include O_2 or CO_2. Except for system breakdowns, repairs, calibration checks, zero and span adjustments, and other quality assurance tests, the Continuous Emission Monitoring Systems (CEMS) shall be in continuous operation and shall record a minimum of four, and normally 60, approximately equally spaced data points for each full hour. The NO_X and diluents CEMS shall be operated according to the methods and procedures as set out in 40 CFR Part 60, Appendix B, Performance Specifications 2 and 3. The CO CEMS shall be operated according to the methods and procedures as set out in 40 CFR Part 60, Appendix B, Performance Specifications 4, 4A, or 4B. CEMS shall follow the quality assurance requirements of Appendix F except that Cylinder Gas Audits may be conducted in all four calendar quarters in lieu of the annual Relative Accuracy Test Audit. A CEMS with downtime due to breakdown or repair of more than 10% of the facility operating time for any calendar shall be considered as a defective CEMS and the CEMS shall be replaced within 2 weeks.
Engines & Turbines	Biennial Testing Any engine greater than 500 horsepower or any turbine	Every two years starting from the completion date of the Initial Compliance Testing, any engine greater than 500 horsepower or any turbine shall be retested according to the procedures of the Initial Compliance Testing. Retesting shall occur within 90 days of the two-year anniversary date. If a facility has been operated for less than 2000 hours during the two-year period, it may skip the retesting requirement for that period. After biennial testing, any engine retested under the above requirements shall resume periodic evaluations within the next six calendar months (January to June or July to December). If biennial testing is required for an engine that is re-started for production purposes, the biennial testing shall be performed within 45 days after re-starting the engine.
Oxidation	Initial	Stack testing when a company wants to establish

or Combustion Control Device	Sampling and Monitoring for performance for VOC, Benzene, and H_2S	efficiencies of 99% or greater, must be coordinated and approved. Sampling is required for VOC, benzene and H_2S at Region's discretion. The thermal oxidizer (TO) must have proper monitoring and sampling ports installed in the vent stream and the exit to the combustion chamber, to monitor and test the unit simultaneously. The temperature and oxygen measurement devices shall reduce the temperature and oxygen concentration readings to an averaging period of 6 minutes or less and record it at that frequency. The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have an accuracy of the greater of ±0.75% of the temperature being measured expressed in degrees Celsius or ±2.5°C. The oxygen or carbon monoxide analyzer shall be zeroed and spanned daily and corrective action taken when the 24-hour span drift exceeds two times the amounts specified Performance Specification No. 3 or 4A, 40 CFR Part 60, Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days. The oxygen or carbon monoxide analyzer shall be quality-assured at least semiannually using cylinder gas audits (CGAs) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, §5.1.2, with the following exception: a relative accuracy test audit is not required once every four quarters (i.e., two successive semiannual CGAs may be conducted). An equivalent quality-assurance method approved by the TCEQ may also be used. Successive semiannual audits shall occur no closer than four months. Necessary corrective action shall be taken for all CGA exceedances of ±15 percent accuracy and any continuous emissions monitoring system downtime in excess of 5% of the incinerator operating time. These occurrences and corrective actions shall be reported to the appropriate TCEQ Regional Director on a quarterly basis. Supplemental stack concentration measurements may be required at the discretion of the appropriate

		TCEQ Regional Director. Quality assured or valid data of oxygen or carbon monoxide analyzer must be generated when the TO is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, inaccurate data, repair, maintenance, or calibration may be exempted provided it does not exceed 5% of the time (in minutes) that the oxidizer operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.
Vapor Recovery Systems	Sampling to determine effectiveness	lVRU. The testing requires that a sample is analyzed using a PID and Method 21 or modified Method 21. Both the inlet and the outlet streams would need to be tested, and the difference would determine the efficiency. The equation is as follows: based on PID results, the mathematical equation to determine efficiency is *1-(inlet-outlet)/inlet*. This testing needs to be performed and results recorded to receive 95% control efficiency no longer than: vacuum truck emissions: after 20 loads have been pulled through the lVRU, for tanks: Produced Water – Monthly, Crude – Bi-Monthly, Condensate – Weekly. This testing needs to be performed and results recorded to receive 98% control efficiency no longer than: vacuum truck emissions: after 15 loads have been pulled through the lVRU, for tanks: Produced Water – 3 weeks, Crude – 10 days, Condensate – 5 days.

Table 8: Monitoring and Records Demonstrations

Category	Description	Record Information
Site Production or Collection	natural gas, oil, condensate, and water production records	Site inlet and outlet gas volume and sulfur concentration, daily gas/liquid production and load-out from tanks
Equipment and facility summary	Current process description	Accurate and detailed plot plan with property line, off-site receptors, and all equipment on-site or drawings with sufficient detail to confirm all authorized facilities meet the requirements including, but not limited to, emission estimates, impact review, and registration scope.
Equipment specifications	Process units, tanks, vapor recovery systems; flares; thermal oxidizers; and reboiler control devices	A copy of the registration and emission calculations including the stationary equipment sizes and/or capacities and manufacturer's specifications and programs to maintain performance, with the plan and records for routine inspection, cleaning, repair and replacement.
Physical Inspection	Fugitive Component Check	A record of the component count shall be maintained. A record of the date each quarterly inspection was made and the date that components were found leaking and when repaired or the date of the next planned shutdown.
Voluntary LDAR Program	Details of fugitive component monitoring plan, and LDAR results, including QA, QC	The following records are required where a company uses an LDAR program to reduce the potential fugitive emissions from the site to meet emission limitations or certify fugitive emissions. (A) A monitoring program plan must be maintained that contains, at a minimum, the following information: (i) an accounting of all the fugitive components by type and service at the site with the total uncontrolled fugitive potential to emit estimate; (ii) identification of the components at the site that are required to be monitored with an instrument or are exempt with the justification, note the following can be used for this purpose: (a) piping and instrumentation diagram (PID); or (b) a written or

		electronic database.; (iii) the monitoring schedule for each component at the site with difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), identified and justified, note if an unsafe-to-monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times and a record of the plan to monitor shall be maintained; and (iv) the monitoring method that will be used (audio, visual, or olfactory (AVO) means; Method 21; the Alternative Work Practice in 40 CFR §60.18(g) - (i)); (v) for components where instrument monitoring is used, information clarifying the adequacy of the instrument response; (vi) the plan for hydraulic or pressure testing or instrument monitoring new and reworked components. (B) Records must be maintained of all monitoring instrument calibrations. (C) Records must be maintained for all monitoring and inspection data collected for each component required to be monitored with a Method 21 portable analyzer that include the type of component and the monitoring results in ppmv regardless if the screening value is above or below the leak definition.. (D) Leaking components must be tagged and a leaking-components monitoring log must be maintained for all leaks greater than the applicable leak definition (i.e.10,000 ppmv, 2000 ppmv, or 500 ppmv) of VOC detected using Method 21, all leaks detected by AVO inspection, and all leaks found using Alternative Work Practice specified in 40 CFR §60.18(g)-(i). The log must contain, at a minimum, the following: (i) the method used to monitor the leaking component (audio, visual, or olfactory inspection; Method 21; or the Alternative Work Practice in 40 CFR §60.18(g) - (i)); (ii) the name of the process unit or other appropriate identifier where the component is located; (iii) the type (e.g., valve or seal) and tag identification of component; (iv) the results of the monitoring (in ppmv if a Method 21 portable analyzer was used); (v) the date the leaking component was discovered;(vi) the date that a first attempt at repair was made to a leaking component; (vii) the date that a

		leaking component is repaired; (viii) the date and instrument reading of the recheck procedure after a leaking component is repaired; and (ix) the leaks that cannot be repaired until turnaround and the date that the leaking component is placed on the shutdown list. (E) If the owner or operator is using the Alternative Work Practice specified in 40 CFR §60.18(g) - (i), the records required by 40 CFR §60.18(i)(4). (F) A record of the monitored value any open-ended line or valve for which a repair or replacement is not completed within 72 hours and monitoring in lieu of covering is chosen. (G) Audio, visual and olfactory inspections shall occur quarterly for BMP and at least weekly in concert with required instrument monitoring programs by operating personnel walk-through and be recorded. (H) A check of the reading for any pressure-sensing device to verify rupture disc integrity shall be performed weekly.
Minor Changes	Additions, changes or replacement of components or facilities	Records showing all replacements and additions, including summary of emission type and quantities for a rolling 60-month period.
Equipment Replacement	Like-Kind replacement	Records on equipment specifications and operations, including summary of emissions type and quantity.
Process Units	Glycol Dehydration Units	For emission estimates, the worst-case combination of parameters resulting in the greatest emission rates must be used. If worst-case parameters are not used, then glycol dehydrator unit monitoring records include dry gas flow rate, absorber pressure and temperature, glycol type, and circulation rate recorded weekly. If worst-case parameters are not used, then in addition to weekly unit monitoring where control of flash tank or reboiler emissions are required to meet the emission limitations of the section and emissions are certified, the following control monitoring requirements apply weekly: flash tank temperature and pressure, any reboiler stripping gas flow rate, and condenser outlet temperature. VRU, flare, or thermal oxidizer control or reboiler fire box used for control must comply with the monitoring and recordkeeping for those devices. Where all emissions from the flash tank and the reboiler or

		reboiler condenser vent are directed to a VRU, flare, or thermal oxidizer designed to be on-line at all times the glycol dehydrator is in operation, the control system monitoring for the glycol dehydrator is not required.
	Amine units	Amine units may simply retain site production or inlet gas records if all sulfur compounds in the inlet are assumed to be emitted. Where only partial removal of the inlet sulfur is assumed, for emission estimates, the worst-case combination of parameters resulting in the greatest emission rates must be used. If worst-case parameters are not used, then records of the amine solutioncontactor pressure, temperature and pump rate. Where the waste gas is vented to combustion control, the requirements of the control device utilized should be noted.
Boilers, Reboilers, Heater-Treaters, and and Process Heaters	Combustion	Records of Operational Monitoring and Testing Records Records of the hours of operation of every combustion device of any size by the use of a process monitor such as a run time meter, fuel flow meter, or other process variable that indicates a unit is running unless, in the registration for the facility, the emissions from the facility were calculated using full-year operation at maximum design capacity in which case no hours of operation records must be kept.
Internal Combustion Engines	Combustion	Records of Appropriate Operational Monitoring and Testing Records. Records of the hours of operation of every combustion device and engine of any size by the use of a process monitor such as a run time meter run time meter, fuel flow meter, or other process variable that indicates a unit is running. The owner or operator may choose to undergo testing and re-testing at the most frequent intervals identified in Table 7 in lieu of installing a process monitor and recording the hours of operation. If an engine has no testing requirements in Table 7 of this subsection, no records of the hours of operation must be kept. See fuel records below
Gas Fired Turbines	Combustion	Records of Appropriate Operational Monitoring and Testing Records Records of the hours of operation of every turbine greater than 500 hp by the use of a process monitor

		such as a run time meter, fuel flow meter, or other process variable that indicates a unit is running unless the permit holder determined emissions from the facility assuming full year operation at maximum design capacity in which case no hours of operation records must be kept.
Fuel Records	VOC and Sulfur Content	A fuel flow meter is not required if emissions are based on maximum fuel usage for 8,760 hr/yr. There are no specific requirements for allowable VOC content of fuel. If field gas contains more than 1.5 grains (24 ppmv) of H_2S or 30 grains total sulfur compounds per 100 dry standard cubic feet, the operator shall maintain records, including at least quarterly measurements of fuel H_2S and total sulfur content, which demonstrate that the annual SO_2 emissions do not exceed limitations
Tanks/Vessels	Color/Exterior	Records demonstrating design, inspection, and maintenance of paint color and vessel integrity.
Tanks/Vessels	Emission and emission potential	Maintain a record of the material stored in each tank/vessel that vents to the atmosphere and the maximum vapor pressure used to establish the maximum potential short-term emission rate. Where pressurized liquids can flash in the tank/vessel monitor and record weekly the maximum fluid pressure that can enter the tank/vessel. Records that tank/vessel hatches and relief valves are properly sealed when tank/vessel is directed to control and after loading events (as needed).
Truck Loading	All Types	Records indicating type of material loaded, amount transferred, method of transfer, condition of tank truck before loading.
	Vacuum Trucks	Note loading with an air mover or vacuum. No additional record is needed where a vacuum truck uses only an on-board or portable pump to push material into the truck.
	Controlled Loading	Where control is required note the control that is utilized.
	Tank Truck Certification	Records of tank truck certifications and testing. Records are only required if connection to control is used and credit is claimed for certified truck use.
Cooling Tower	Design data	Records shall be kept of maximum cooling water circulation rate and basis, maximum total dissolved solids allowed as maintained through blowdown, and

		towers design drift rate. These records are only required if the cooling system is used to cool process VOC streams or control from drift eliminators or minimizing solids content is needed to meet particulate matter emission limits.
	VOC Leak Monitoring, Maintenance and Repair	Cooling tower heat exchanger systems cooling process VOC streams are assumed to have potential uncontrolled leaks repaired when obviated by process problems. If controlled emissions (systems monitored for leaks) are required to meet emission rate limits then the cooling tower water shall be monitored monthly for VOC leakage from heat exchangers in accordance with the requirements of the TCEQ Sampling Procedures Manual, Appendix P (dated January 2003 or a later edition) or another air stripping method approved by the TCEQ Commission. Cooling water VOC concentrations above 0.08 parts per million by volume (ppmv) indicate faulty equipment. Equipment shall be maintained so as to minimize VOC emissions into the cooling water. Faulty equipment shall be repaired at the earliest opportunity but no later than the next scheduled shutdown of the process unit in which the leak occurs. Records must be maintained of all monitoring data and equipment repairs.
	Particulate Monitoring, Maintenance and Repair.	Inspect and record integrity of drift eliminators annually, repairing as necessary. If a maximum solids content must be maintained through blowdowns to meet particulate emission rate limits, cooling water shall be sampled for total dissolved solids (TDS) once a month prior to any periodic blowdowns and maintain records of the monitoring results and all corrective actions.
Planned Maintenance, Startup, and Shutdown (MSS)	Alternate Operational Scenarios and Redirection of Vent Streams	Records of redirection of vent streams during primary operational unit or control downtime, including associated alternate controls, releases and compliance with emission limitations.
Planned MSS	Pigging, Purging and Blowdowns	Pigging records, including catcher design, date, emission estimate to atmosphere and to control, and when controlled, the control device. Note: where a control device is necessary to meet emission limitations, the device is subject to the requirements

		of section (e) of this section and record requirements of this table. Purging and blowdown records, including the volume and pressure and a description of the piping and equipment involved, the date, emission estimate to atmosphere and to control, and when controlled, the control device. Where purging to control to meet a lower concentration before purging to atmosphere is conducted the concentrations of VOC, BTEX or H_2S, as appropriate, must be measured and recorded prior to purging to atmosphere. Note where a control device is necessary to meet emission limitations the device is subject to the requirements of section (e) of this section and record requirements of this table.
Planned MSS	Temporary Facilities for Bypass, and Degassing and Purging	Temporary facility records, including a description and estimate of potential fugitive emissions from temporary piping, size and design of facilities (eg. tanks or pan volume, fill method, and throughput; engine horse power, fuel and usage time, flare tip area, ignition method, and heating value assurance method; etc.) and the date and emission estimate to atmosphere and to control for their use
Planned MSS	Management of Sludge from Pits, Ponds, Sumps and Water Conveyances	Records including the source and stream identification, removal plan, emission estimate that are direct to atmosphere and through a control. Note: where a control device is necessary to meet emission limitations, the device is subject to the requirements of section (e) of this section and record requirements of this table.
Planned MSS	Degassing or Purging of Tanks, Vessels, or Other Facilities	Records including: a) the EPN and description of vessels and equipment degassed or purged, with; b) the material, volume and pressure (if applicable); c) the volume of purge gas used; d) a description of the piping and equipment involved; e) clarifying estimates for a coated surface or heel; f) the date; g) emission estimate to atmosphere and to control; h) when controlled, the control device; and i) where purging to a control device to reduce

		concentrations before purging to atmosphere, the concentrations of VOC, BTEX or H_2S as appropriate must be measured and recorded prior to purging to atmosphere. j) the permit holder shall maintain a record of the estimated calculation demonstrating the benefit of a delay inrepair and provide upon request to a regulatory agency with jurisdiction.
Planned MSS	Records	Records or copies of work orders, contracts, or billing by contractors for the following activities shall be kept at the site, or nearest manned site, and made available upon request: • Routine engine component maintenance including filter changes, oxygen sensor replacements, compression checks, overhauls, lubricant changes, spark plug changes, and emission control system maintenance; • Boiler refractory replacements and cleanings; • Heater and heat exchanger cleanings; • Turbine hot section swaps; • Pressure relief valve testing, calibration of analytical equipment; instrumentation/analyzer maintenance; replacement of analyzer filters and screens.
Control Devices	Flare Monitoring	Basic monitoring requires the flare and pilot flame to be continuously monitored by a thermocouple or an infrared monitor. Where an automatic ignition system is employed, the system shall ensure ignition when waste gas is present. The time, date, and duration of any loss of flare, pilot flame, or auto-ignition shall be recorded. Each monitoring device shall be accurate to, and shall be calibrated at a frequency in accordance with, the manufacturer's specifications. A temporary, portable or backup flare used less than 480 hours per year is not required to be monitored. Records of hours of use are required for all units and on-line time must be considered when emission estimates and actual emissions inventories are calculated.
Control Devices	Thermal Oxidation and Vapor Combustion	Control device monitoring and records are required only where the device is necessary for the site to meet emission rate limits. Basic monitoring is a thermocouple or infrared

	Performance Monitoring Basic	monitor that indicates the device is working. Records of hours of use are required for all units and on-line time must be considered when emission estimates and actual emissions inventories are calculated.
	Intermediate	Intermediate monitoring and records include continuously monitoring and recording temperature to insure the control device is working when waste gas can be directed to the device and showing compliance with the 1400 degrees Fahrenheit if applicable.
	Enhanced	Enhanced monitoring requires continuous temperature and oxygen or carbon monoxide monitoring on the exhaust with six minute averages recorded to show compliance with the temperature requirement and the design oxygen range or a CO limit of 100 ppmv. Some indication of waste gas flow to the control device, like a differential pressure, flow monitoring or valve position indicator, must also be continuously recorded, if the flow to the control device can be intermittent.
	Alternate Monitoring	Records of stack testing and the monitored parameters during the testing shall be maintained to allow alternate monitoring parameters and limits.
Control Devices	Vapor Capture and Recovery	Records of hours of use are required for all units and on-line time must be considered when emission estimates and actual emissions inventories are calculated. mVRU Basic Design Function Record: Record demonstrating the unit captures vapor and includes a sensing device set to capture this vapor at peak intervals. Additional Design Parameter Record: Record demonstrating additional design parameters are utilized such as additional sensing equipment, a properly designed bypass system, an appropriate gas blanket, an adequate compressor selection, and the ability to vary the drive speed for units utilizing electric driven compressors mVRUs that are used at oil and gas sites to control emissions may claim up to 100% control efficiency provided records of basic and additional design functions and parameters of a VRU along with appropriate records listed in Table 8 are satisfied.

		mVRUs may claim up to 99% control efficiency for units where records of basic and additional design functions are satisfied and parameters listed in Table 8 are not satisfied. mVRUs may claim up to 95% control efficiency for units where records listed in Table 8 are not satisfied. lVRU The record of proper design must be kept to demonstrate how the unit was designed and for what capacity. The record of liquid replacement must be kept, along with the calculations for demonstrating that the VOC to liquid ratio has been maintained. Additionally, the system must be tested to demonstrate the efficiency. This testing needs to be performed and results recorded to receive 95% control efficiency no longer than: vacuum truck emissions: after 20 loads have been pulled through the lVRU, for tanks: Produced Water – Monthly, Crude – Bi-Monthly, Condensate – Weekly. This testing needs to be performed and results recorded to receive 98% control efficiency no longer than: vacuum truck emissions: after 15 loads have been pulled through the lVRU, for tanks: Produced Water – 3 weeks, Crude – 10 days, Condensate – 5 days. All valves must be designed and maintained to prevent leaks. All hatches and openings must be properly gasketed and sealed with the unit properly connected. Downtime is limited to a rolling 12 month average of 5% or 432 hr/per rolling 12 months and waste vents shall be redirected to an appropriate control device if possible during down time unless otherwise certified for alternate operating hours.
Control Devices	Control with process combustion or heating devices (e.g. reboilers, heaters &	Basic monitoring is any continuous monitor that indicates when the flame in the device is on or off (other than partial operational use). The following are effective basic options: a fire box temperature monitor, rising or steady process temperature monitor, CO monitor, primary fuel flow monitor, fire box pressure monitor or equivalent.

	furnaces)	Enhanced monitoring for 91 to 99% control, where waste gas is not introduced as the primary fuel, must include the following monitors: continuous fire box or fire box exhaust temperature, and CO and O_2 monitoring, with at least 6 minute averages recorded. Additionally, enhanced monitoring where the waste gas may be flowing when the control device is not firing must show continuous disposition of the waste gas streams, including continuous monitoring of flow or valve position through any potential by-pass to the control where more than 50% run time of control is claimed.

Table 9 Fugitive Component Leak Detection and Repair (LDAR) Control Program Table

General: All fugitive components at an OGS registered with this rule need to be evaluated for potential emissions with the Oil and Gas factors for impact analysis. The requirements of this table and requirements regarding fugitive component monitoring in Tables 7 and 8 of this subsection must be met to apply LDAR control program reductions in this table. Compliance with these requirements does not assure compliance with requirements of NSPS, NESHAPS or MACT or State Regulations, and does not constitute approval of alternate standards for those regulations.	**Note:** where the estimated emissions from an OGS registered with this rule can meet emission limitations of the rule without reductions of an LDAR control program, then any LDAR control program may be implemented without being subject to these requirements.
Exceptions *If implemented by the permit holder and relied upon for emission reductions, fugitive components must meet the minimum design, monitoring, control, and other emissions techniques listed in this Table unless the component's service meets one of the following exceptions:*	**Additional Details**
Nitrogen lines	No expectation to estimate emissions. Note this exemption does not include lines with nitrogen that has been used as a sweep gas.
Steam lines (non contact)	No expectation to estimate emissions.
Flexible plastic tubing≤ 0.5 inches in diameter, unless it is subject to monitoring by other state or federal regulations.	No expectation to estimate emissions, unless it is subject to monitoring by other state or federal regulations.
The operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure	No expectation to estimate emissions.
Mixtures in streams where the VOC has an aggregate partial pressure of less than	No expectation to estimate emissions.

0.002 psia at 68°F.	
Components containing only noble gases, inerts such as CO_2 and water or air contaminants not typically listed on a MAERT such as methane, ethane, and Freon.	No expectation to estimate emissions.
Instrument monitoring is not required for pipeline quality sweet natural gas	Uncontrolled Emissions should be estimated. Must meet pipeline quality specifications
Instrument monitoring is not required when the aggregate partial pressure or vapor pressure is less than 0.044 psia at 68 ºF or at maximum process operating temperature.	Uncontrolled Emissions should be estimated. This applies at all times, unless a control efficiency is being claimed for instrument monitoring, in which case there must be a record supporting that the instrument could detect a leak.
Instrument monitoring is not required for waste water lines containing less than 1% VOC by weight and operated at ≤ 1 psig	Uncontrolled Emissions should be estimated.
Instrument monitoring is not required for cooling water line components	Emissions are estimated and associated with the cooling tower
Instrument monitoring is not required for CO_2 lines after VOC is removed. This is referred to as Dry Gas lines in 40 CFR Part 60 Subpart KKK, and defined as a stream having a VOC weight percentage less than 4 %; a weighted average Effects Screening Level (ESL) of the combined VOC stream is > 3,500 $\mu g/m^3$; and total uncontrolled emissions for all such sources is < 1 ton per year at any OGS.	Uncontrolled Emissions should be estimated as follows: The weighted average ESL_x for process stream, X, with multiple VOC species will be determined by: $ESL_x = \; fa/ESL_a + f_b/ESL_b + f_c/ESL_c + \ldots.. + fn/ESL_n$ Where: n =total number of VOC species in process stream; ESL_n = the effects screening level in $\mu g/m^3$ for the contaminant being evaluated (published in the most recent edition of the TCEQ ESL list); f_n=the weight fraction of the appropriate VOC species in relation to all other VOC in process stream.
Requirements	**Additional Details and Reduction Credit**
Construction of new and reworked piping,	

valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.	
New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.	
New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter.	
Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Where technically feasible new and reworked components may be screened for leaks with a soap bubble test within 8 hours of being returned to service in lieu of instrument testing. Adjustments shall be made as necessary to obtain leak-free performance.	
Components shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.	The weekly physical inspection applies a 30 % reduction credit to all fugitive components not subject to an instrument monitoring check.
Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line so that no leakage occurs. Except during sampling, both valves shall be closed. If the removal of a component for repair or replacement results in an open ended line or valve, it is exempt from	Application of this requirement eliminates the expectation to estimate emissions from open ended lines and valves.

the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period; i. a cap, blind flange, plug, or second valve must be installed on the line or valve; or ii. the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once at the end of the 72 hour period following the creation of the open ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings 20 ppmv above background and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve.	
Accessible valve shall be monitored by leak-checking for fugitive emissions quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. If an unsafe-to-monitor valve is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times. A difficult-to-monitor component for which quarterly monitoring is	Sealless/leakless valves and relief valves equipped with rupture disc or venting to a control device and exempted from instrument monitoring are not counted in the fugitive emissions estimates. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements. See Table 8, Monitoring and Records Demonstrations to identify Difficult-to-monitor and unsafe-to-monitor valves.

specified may instead be monitored annually. For relief valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity and checked weekly. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.	
All pump, compressor and agitator seals shall be monitored quarterly with an approved gas analyzer or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be instrument monitored. Seal systems that prevent emissions may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure or seals degassing to vent control systems kept in good working order. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.	Pumps compressor and agitator seals that prevent leaks or direct emissions from the seals to control and are exempt from instrument monitoring are not counted in the fugitive emissions estimates. Equipment equipped with alarms would still be counted. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements.
Components found to be emitting VOC in excess of a 10,000 parts per million by volume (ppmv) leak definiton using EPA Method 21, found by visual inspection to be leaking (e.g. whistling, dripping or blowing process fluids or emitting hydrocarbon or H_2S odors) or found leaking using the Alternative Work Practice in 40 CFR §60.18(g) - (i) shall be considered to be leaking and shall be	Components subject to routine instrument monitoring with an approved gas analyzer or the alternative work practice under this leak definition my claim a 75% emission reduction credit when evaluating controlled fugitive emission estimates. This reduction credit does not apply when evaluating uncontrolled emission or to any component not measured with an

repaired, replaced, or tagged as specified.	instrument quarterly. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements
Components <u>**not**</u> subject to a instrument monitoring program but found to be emitting VOC in excess of 10,000 ppmv leak definiton using EPA Method 21, found by audio, visual or olfactory inspection to be leaking (e.g. whistling, dripping or blowing process fluids or emitting hydrocarbon or H_2S odors) shall be considered to be leaking and shall be repaired, replaced, or tagged as specified. All components are subject to monitoring when using the Alternative Work Practice in 40 CFR §60.18(g) - (i).	
Components shall be repaired in accordance with subsection (e)(6)(D) of this section.	Every reasonable effort shall be made to repair a leaking component. At manned sites, leaks shall be repaired within 30 days after the leak is found. At unmanned sites, leaks shall be repaired within 60 days after the leak is found. If the site has a planned shutdown schedule and 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 planned shutdown.
Instrument monitoring and the reduction credit associated may not be applied to components where the gas saturation concentration of the fluid contained would be below the leak definition.	Where components fluids contain sufficient methane and ethane to allow detection by the instrument monitoring the components can be monitored and take the emission reduction credit.
Enhanced LDAR Monitoring Options	Any site may reduce the controlled fugitive emission estimates by including

	components not required to be monitored in the quarterly instrument monitoring program or applying the lower leak definition of the more stringent program as appropriate.
Component groups (eg. flanges and connectors) may implement quarterly instrument monitoring using EPA Method 21 with a leak definition of 10,000 ppmv.	Quarterly monitoring at a leak definition of 10,000 ppmv would equate to a 75% emission reduction credit when evaluating controlled fugitive emission estimates for the instrument monitored component group.
A lower leak definition of 2000 ppmv may be applied to pump, compressor, and agitator seals when instrument monitoring using EPA Method 21 quarterly.	OGS using this lower leak definition for pump, compressor, and agitator seals may apply an 85% emission reduction credit for quarterly monitoring of those components. This reduction credit does not apply when evaluating uncontrolled emissions or to any component not measured with an instrument quarterly. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements.
A lower leak definition of 500 ppmv may be applied to any fugitive component group when instrument monitoring using EPA Method 21 quarterly.	OGS using this lower leak definition for valves, flanges or connectors may apply a 97% emission reduction credit; pumps may apply a 93% emission reduction credit; and compressor, agitator seals and other component groups may apply a 95% emission reduction credit for quarterly monitoring of those components. This reduction credit does not apply when evaluating uncontrolled emission or to any component not measured with an instrument quarterly. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements.

Instrument Monitoring Frequency Adjustments	
After completion of the required quarterly inspections for a period of at least two years, the operator of the OGS facility may change the monitoring schedule as follows: (i) After two consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip one of the quarterly leak detection periods for the valves in gas/vapor and light liquid service; (ii) After five consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip three of the quarterly leak detection periods for the valves in gas/vapor and light liquid service. If the owner or operator is using the Alternative Work Practice in 40 CFR §60.18(g) - (i), the alternative frequencies specified in this standard permit are not allowed.	At the discretion of the TCEQ Commission or designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.