

AIR QUALITY STANDARD PERMIT FOR OIL AND GAS HANDLING AND PRODUCTION FACILITIES

Note for all Readers: Acronym List at End of Document

I. EXECUTIVE SUMMARY

The commission is in the process of evaluating all permits by rule (PBR) and standardized authorizations (standard permits) through a multiple-phased process known as the PBR Study. The goals of the study include: updating administrative and technical requirements; making appropriate changes to registration or notification requirements; ensuring that air emissions from specific facilities are protective of public health and welfare; including practically enforceable record requirements; authorizing planned maintenance, startup, and shutdown (MSS) activities; and allowing the commission to more effectively focus resources on facilities that significantly contribute air contaminants to the atmosphere. Through this study, the commission has determined a need to significantly revise the PBR and standard permit for oil and gas facilities or groups of facilities at a site (OGS). In addition, recent commission evaluations of monitoring data indicates updated regulatory oversight would be beneficial to ensure protectiveness for air contaminants such as benzene, hydrogen sulfide (H₂S), and other air contaminants associated with oil and gas production sites. These updates are particularly critical for OGS in urban locations or in close proximity to the public. Overall, this rulemaking is necessary to ensure that authorizations for OGS are improved for enforceability and updated based on current scientific information, and to properly regulate all operations.

The oil and gas industry appears to be in the midst of a new boom. New technologies have made hydraulic fracturing an economical possibility and have allowed industry to tap into shale gas that was previously far too expensive to extract. This new boom is the result of technologies and methods that have evolved over the years. While the technology for drilling wells and producing oil and gas has evolved, the laws governing this industry have not. Texas still operates under the same standard permit that it adopted in 1996. Essentially, Texas is applying 14 year old standard permits to an industry where science and technology are evolving on a daily basis. Not only has science and technology allowed us to tap into previously unattainable resources, it has also allowed us to better understand the effect of oil and gas drilling and production operations have on public health and the environment. Again, the most up to date science and emission detection systems have greatly evolved over the past 14 years. Unfortunately, our laws have not. While the standard permit reflected current science in 1996, it does not reflect current science in 2010. The science of 2010 dictates that the PBR and standard permit be updated in order to allow increased air emissions and protect public health and the environment.

The commission is issuing a new non-rule standard permit for the construction and modification of oil and gas facilities which will replace Title 30 Texas Administrative Code (30 TAC) §116.620, Installation and/or Modification of Oil and Gas Facilities for new and modified facilities. The new PBR and standard permit are adopted and issued to provide an updated, comprehensive, and protective authorization for many common OGS in Texas. The new PBR and standard permit include operating specifications and emissions limitations for typical equipment (facilities) during normal operation, which includes production and planned MSS. The PBR and standard permit will specifically address the appropriateness of multiple authorizations at one contiguous property and would reference the many new federal standards which have been promulgated by the United States Environmental Protection Agency (EPA), as well as include revised criteria for registration and changes at existing authorized sites.

II. HIERARCHY OF AIR AUTHORIZATIONS

Texas Health and Safety Code (THSC), §382.0518 establishes regulations for all facilities which may have the potential to emit air contaminants to obtain an air authorization and meet appropriate emission limits and control requirements. To ensure that the administrative and technical requirements for facilities are appropriate to their potential emissions releases, the commission has established a hierarchy of authorization mechanisms. The most negligible sources are covered under 30 TAC §116.119, De Minimis Facilities or Sources, and by definition, do not have substantial limitations or requirements. Facilities which are not *de minimis*, but instead are insignificant, can be authorized under Chapter 106. The PBRs are rules with general and specific requirements promulgated by the commission. PBRs are usually specific to an industry or activity. A facility or group of facilities authorized by PBR must meet each condition of the rule exactly, with no exceptions. The next category of authorizations is a standard permit issued under 30 TAC Chapter 116, Subchapter F, Standard Permits, which are more complex than PBRs, but do not require case-by-case reviews or trigger federal pre-construction authorization. The standard permits are also usually specific to an industry or defined activity at a site. A facility or group of facilities authorized by standard permit must meet each condition of the standard permit exactly, with no exceptions. The next category of available authorizations is case-by-case state new source review (NSR) permits issued under 30 TAC §116.111, General Application. Specific permit conditions and limitations are reviewed and negotiated during these permit reviews for sources which are not *de minimis*, insignificant, or cannot meet PBR or standard permit requirements. For new major sources or major modifications at existing major sources, federal preconstruction permit reviews are required.

III. EXPLANATION AND BACKGROUND OF AIR QUALITY STANDARD PERMIT

Currently, an OGS may be authorized by PBR, standard permit, case-by-case NSR permit, or a combination of these authorizations. This standard permit and the corresponding PBR were developed to provide an updated, comprehensive, and protective authorization for many common OGS and facilities in Texas. The standard permit includes specifications and limitations for typical equipment (facilities) during normal operation, including production as well as planned maintenance, startup, and shutdown (MSS). The PBR and standard permit have been developed considering current emission capture and control equipment.

There have also been historical concerns regarding the use of multiple authorizations for related and unrelated facility operations at the same site or location. The standard permit and PBR address the appropriateness of multiple authorizations at one contiguous property. This standard permit issuance also includes revised criteria for registration and changes at existing, authorized sites.

One of the continuing limitations for the standard permit would limit the authorizations to OGS which do not require federal preconstruction authorization under Title 40 Code of Federal Regulations (40 CFR) Part 51 (Prevention of Significant Deterioration [PSD]) or 40 CFR Part 52 (Nonattainment New Source Review [(NNSR])). New and existing OGS may be subject to the Title V federal operating permit program as well and must obtain a Site Operating Permit (SOP) or a General Operating Permit (GOP). Based on recent regulatory changes required by EPA and 40 CFR Part 70, a GOP can only be used by sites authorized under PBR or standard permit. If a major site subject to Title V does not qualify for a PBR or standard permit, it must obtain a SOP (submittal deadline was December 2008).

A primary goal of the PBR study is to verify that all general authorizations of the commission, such as PBRs and standard permits, are protective of human health and welfare and recommend rule changes to ensure or improve their continued protectiveness. To achieve this goal, impacts evaluation was conducted to verify that individual PBR or standard permit claims will not adversely impact public health and welfare, that is, be “protective.”

For each type or group of typical OGS facilities and activities, the executive director’s staff analyzed the following questions: what is the facility; how does it operate; what is its function; what was the basis for the information used; how are emissions from production operations generated, estimated and released; what is the expected type and quantity of emissions from production; what are the appropriate capture or control systems for production operations; what are the appropriate best management practices (BMP) and/or best available control technology (BACT) for this facility; what are the emission dispersion characteristics for production; and are the impacts of the emissions protective of public health and welfare. In addition, for related operations and activities at OGS, the commission reviewed the following: what is planned MSS; how are emissions from planned MSS activities generated, estimated and released; what is the expected type and quantity of emissions from MSS; what are the appropriate capture or control systems for MSS activities; what is the appropriate BACT for this MSS activity; what are the emission dispersion characteristics for MSS emissions; and are the impacts of the emissions protective of public health and welfare.

In 2006, the commission distributed a preliminary proposal for the OGS, which included updates based on science and emissions information available at the time. This package was discussed at numerous stakeholders meetings and evaluated by state and federal regulatory staff. At the time, it was determined that additional, detailed, information was needed to ensure a more comprehensive and representative review of facilities, controls, and emissions associated with OGS. Research in many areas has continued for several years, and the results of those efforts are included in this standard permit. In addition, numerous comments were received from the regulated community, mainly expressing concerns over more detailed and prescriptive emission limits, sampling and monitoring requirements, preconstruction registrations, and control specifications.

Any OGS under a standard permit may only consist of the facilities and operations evaluated by the commission. The executive director’s staff evaluated the following facilities historically referred to as “oil and gas production facilities” claimed under §106.352, as well as numerous other PBRs, and the oil and gas standard permit including: fixed-roof, internal floating roof, external floating roof and pressurized tanks storing or transferring crude oil, natural gas, condensate, liquid petroleum gas, fuel oil, diesel fuel, gasoline, amine treatment chemicals, glycol treatment chemicals, methanol, speciated liquids and gases, produced and salt water, and slop/sump oil; liquid and gas truck loading and pipeline transfer facilities; separators (free-water knockouts, gunbarrels, oil/water separators, membrane units); condensers; treatment units (heat exchangers, refrigeration units, glycol dehydration units, amine units and other sweetening units, heater treaters, methanol injection, molecular/mole sieves, absorbers, or adsorbers); natural gas liquid recovery units (cryogenic expansion, refrigeration, absorption, adsorption processes); compressors, pumps, and meters; fugitive components (valves, pipe flanges and connectors, pump and compressor seals, and process drains); cooling towers and in-direct heat exchangers; combustion units (boilers, reboilers, heaters, heater treaters, reciprocating engines and turbines, flares, thermal destruction devices); and other facilities meeting the conditions of certain permits by rule in 30 TAC Chapter 106 including: §106.181, Used Oil Combustion Units; Boilers; §106.183, Heaters and Other Combustion Devices; §106.261, Facilities (Emission Limitations); §106.262, Facilities (Emissions and Distance Limitations); §106.264, Replacements of Facilities;

§106.351, Salt Water Disposal (Petroleum); §106.352, Oil and Gas Production Facilities; §106.353, Temporary Oil and Gas Facilities; §106.371, Storage and Handling of Dry Natural Gas; §106.472, Organic and Inorganic Liquid Loading and Unloading; §106.473, Organic Liquid Loading and Unloading; §106.475, Pressurized Tanks or Tanks Vented to a Firebox; §106.476, Pressurized Tanks or Tanks Vented to Control; §106.478, Storage Tank and Change of Service; §106.492, Flares; §106.511, Portable and Emergency Engines and Turbines; and §106.512, Stationary Engines and Turbines.

Additional information was requested from stakeholders or researched by the executive director's staff since the previous proposal. Where sufficient information was available, emissions, potential impacts, best management practices (BMP), MSS, and best available control technology (BACT) were considered and used to develop this standard permit for all identifiable facilities, operations and activities. For production operations, the following facilities were reviewed: separators, amine treaters, iron sponge units, glycol reboilers and treaters, cooling towers, cryogenic units and other natural gas liquid recovery units, deethanizers, heat exchangers, engines and turbines, storage tanks and material handling (flash, working, breathing losses for crude oil, condensate, produced water, and natural gas) truck loading, fuel tanks, and slop/sump oil tanks. This review also encompassed all types of treatments and chemicals, including: corrosion inhibitors, surfactants, scale inhibitors, methanol injection, glycols, amines, and other regenerative or non regenerative sweetening systems with solid or liquid treatment chemicals. Particular focus was made for recovery and controls, including vapor recovery systems (VRSs), flares, thermal oxidizers, vapor combustors, and engine catalysts. For planned MSS, certain facilities requiring periodic inspection, cleaning and maintenance included storage tanks, pressurized and non-pressurized process vessels, and associated piping and fugitive components. These activities primarily consist of purging/degassing, opening (interior wetted surface area), cleaning, and refilling/recharging, and returning to service a variety of systems, including: separators, treatment chemicals, methanol injection, glycol dehydrators, molecular sieves, iron sponge, amine treaters, H₂S scavenger chemical reaction vessels for sulfur removal, regenerative or non regenerative sweetening systems with solid or liquid treatment chemicals, cooling towers, cryogenic units, deethanizers, glycol regenerators, absorbers, adsorbers, heat exchangers, boilers, reboilers, heaters, heater treaters, crude oil tanks, condensate tanks, produced water tanks, loading racks, and slop/sump oil tanks. Various capture and control equipment and emission release options was also reviewed, including: alternative operations or diverted stream when control systems are out of service for planned maintenance; additional streams when purging/degassing equipment; flares, thermal oxidizers, vapor combustors; and VRSs. Finally, the commission reviewed temporary maintenance facilities, including abrasive blasting, surface preparation and coating, testing of an engine or turbine, temporary piping and associated facilities to bypass equipment.

IV. FACILITIES, EMISSIONS, AND CONTROLS

The oil and gas production and transportation industry consists of a great variety of handling and processing facilities, emissions, and control devices. The executive director's staff has reviewed hundreds of PBRs, standard permit, and permit files to identify the most common OGS facilities which are similar in terms of operations and processes, resulting in similar potential emissions and corresponding predicted impacts. Most OGS will process gases and liquids associated with the production, conditioning, processing, and pipeline transfer of OGS fluids and gases using a variety of process equipment. These sites use various types of equipment in different ways and arranged in an almost infinite number of possible configurations. Depending on the region in Texas, the composition of the fluids and gases at a given site also varies greatly. It was necessary for the commission to evaluate each type of equipment that is typically found at existing OGS.

The facilities and operations reviewed by the commission are the foundation of this standard permit, and authorizations will be limited to only those facilities, operations, emissions, and controls evaluated. If additional facilities or operations occur commonly at OGS throughout the state, the commission requests detailed information to broaden this evaluation. In some cases, the commission has determined that information is available, but that considerable personnel and resources are needed to establish the facts or the additional required information for consideration may not be readily available or contained in the permit files maintained by the agency. Because information is not available the commission is not including these facilities or activities in any new authorization mechanisms.

It should also be noted that, at a minimum, the standard permit analysis is required by statute to include BACT which is defined in 30 TAC §16.10 as “An air pollution control method for a new or modified facility that through experience and research, has proven to be operational, obtainable, and capable of reducing or eliminating emissions from the facility, and is considered technically practical and economically reasonable for the facility. The emissions reduction can be achieved through technology such as the use of add-on control equipment or by enforceable changes in production processes, systems, methods, or work practice.” BACT considers technology which is technically feasible and economically reasonable. The requirements for BACT determinations consist of three tiers of review. Tier I BACT is those controls or techniques that are commonly used, many have been required in permits for an extended period of time, or have been required in recently issued permits. Tier II BACT is those controls or techniques which have been commonly used or required in similar industries or at sites with similar process streams. Tier II BACT reviews include those controls and techniques that have been determined by a regulatory agency to be technically feasible based on good engineering judgment, but may not have been used or required under Tier I. Tier III BACT consists of reviews for economic reasonableness of certain controls or techniques and provide the opportunity for the regulated entity to justify that a control that is otherwise required under Tier I or II is not economically reasonable to install due to the unique circumstances of their processes.

The following discussions concern the most common facilities, equipment, and operations typically found at an oil and gas site.

A. Fugitive Components

The most universally common facility and associated emission releases at OGS are from fugitives. The federal new source review permitting definition of fugitives is an emission release occurs when any air contaminant enters the atmosphere and cannot reasonably pass through a stack, chimney, vent, or other functionally equivalent opening designed to direct or control its flow. For state permitting purposes, the term fugitive describes emissions from certain equipment, including valves, pipe flanges and connectors, seals, instrumentation, and the like – often are referenced as fugitive components. Normally, control of fugitive emissions involves minimizing leaks through equipment changes, monitoring, housekeeping, and maintenance practices. Fugitive emissions are usually released to the atmosphere at ambient temperature, have little or no velocity, and are often close to the ground.

Air pollutants at OGS from fugitive components include volatile organic compounds (VOC) grouped by the TCEQ into one of three general categories, crude oil, condensate, or natural gas, and containing various levels of hazardous air pollutants (HAPs) such as benzene, toluene, ethylbenzene, and xylene (BTEX); as well as hydrogen sulfide (H₂S).

Emissions that occur during production operations are directly related to the level of preventative measure applied. Fugitive emissions occur as a result of both production and MSS activities, although potentially in substantially different quantities. Emissions during MSS activities are directly related to the amount and type of gas or liquid which remain in the equipment or piping when a seal is broken or opened. Emissions from MSS activities were evaluated and found to be of the same character as production emissions. The fugitive emissions from the repair or replacement of connections was estimated to be similar in character and quantity as pipeline purging or plant blowdowns which are discussed later in this analysis. Based on the limited information available, the executive director's staff assumed fugitive MSS activities occur uncontrolled at OGS.

Normally, control of fugitive emissions involves minimizing leaks and spills through equipment changes, monitoring, housekeeping, and maintenance practices. Maintenance of fugitive components requires purging associated piping and equipment prior to repair or replacement of valves, flanges, and seals. The executive director's staff evaluated emissions and small blocked sections of pipelines which are purged prior to maintenance and repair. In all cases, Tier I BACT requires caps on open-ended lines resulting from repairs if open for more than 72 hours, regardless of size. In addition, current Tier I BACT for piping component fugitive emissions is estimated using emission factors from the October 2000 "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives" TCEQ guidance document. The applicable Leak Detection and Repair (LDAR) program is determined according to the following:

- (1) If uncontrolled annual VOC fugitive emissions are estimated at less than 10 tons per year (tpy), there are no specific LDAR requirements which are universally expected. There are sites which must perform LDAR programs at less than 10 tpy, in accordance with 30 TAC §115.352, Control Requirements, the program referred to as "28RCT" applies.
- (2) If uncontrolled annual VOC fugitive emissions are estimated at equal to or greater than 10 tpy VOC, the 28M LDAR Program (with 10,000 parts per million by volume [ppmv] leak definition) applies.
- (3) If uncontrolled annual VOC fugitive emissions are estimated at equal to or greater than 25 tpy VOC, the 28VHP LDAR Program (with 500 ppmv leak definition) applies.

At sites with a field gas pneumatic power system for the valves, actuators, and pumps, there are VOC gas releases which are considered as working releases from the valves, actuators, or pumps gas vents which are not included in the fugitive component VOC emission factors. These emissions are in addition to the fugitive component VOC emissions. The manufacturer data sheet should be consulted for their emission factor which may have to be modified by the VOC and H₂S content of the field gas. For glycol dehydrators with field gas power pneumatic systems the GLYCalc computer program will estimate these additional emissions for some systems.

Based on investigations and monitoring by TCEQ field personnel and representations in permit reviews, on-going maintenance of fugitive components may not be diligently applied throughout the industry. In some cases, there have been reports of open-ended pipes and seriously leaking components at OGS, thus raising concerns over unaccounted emission releases. The Texas Railroad Commission has also recently issued an advisory to the industry, expressing similar concerns.

Fugitive component emissions from production at OGS were estimated based upon extensive research of registration files and the 1997 Protectiveness Review for Standard Exemption No. 66 (predecessor to PBR §106.352). From this review, the commission estimates a representative, but conservative, number of 1,000 piping components per OGS, including a component breakdown of 700 flanges and 300 valves, with 50 percent of components in gas service and 50 percent in light liquid service (condensate) for a natural gas site. It is assumed that a crude oil site will have a similar component count, though there may or may not be components in natural gas service, instead they will be in crude oil service. To evaluate production emissions, the VOC content was assumed to be 97 percent for liquid condensate service and 40 percent for gas service. A similar analysis was completed for the 1996 review of the initial oil and gas facilities standard permit. Production emissions from these facilities were estimated using emission factors from the October 2000 “Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives” TCEQ guidance document. This document details commonly accepted American Petroleum Institute (API) emission factors. While there have been several previous versions of the API factors for oil and gas sites, the most current and representative are those published in by the United States Environmental Protection Agency “EPA: Protocol for Equipment Leak Emission Estimates” Nov. 1995, EPA 4531, R-95-017 API 46API 4638: “Calculation Workbook for Oil and Gas Production Equipment Fugitive Emissions,” July 1996.

Planned MSS activities on pipelines occur when repairing or replacing fugitive components, purging of the piping, adding additional components, and refilling piping sections. Releases of emissions depend on the size of piping to be purged and the volume of gas it contains. Engine casing emissions and their releases are covered in the compressor blowdowns section.

B. Pumps and Meters

Pumps and pump jacks are used to move material through piping and equipment at an OGS. Pumps may be driven by electric motor, steam, air, natural gas, hydraulics, internal combustion engine, or gas turbine. Electric, steam, and air-driven motors do not produce air contaminants. Internal combustion engines and turbines will have these products of combustion: nitrogen oxides (NO_x), carbon monoxide (CO), VOC, particulate matter 10 microns or less in diameter (PM₁₀), particulate matter 2.5 microns or less in diameter (PM_{2.5}), and sulfur dioxide (SO₂). These facilities are covered in the Combustion Units section. Any discussion of PM from a combustion device includes PM₁₀ and PM_{2.5}, regardless of how it is addressed. Hydraulic motors may have seals and fugitive components with hydraulic fluid emissions. A well-maintained hydraulic system will have de minimis quantities of emissions from hydraulic components. A gas powered pump will emit low pressure gas emissions which are normally considered fugitive emissions after the higher pressure mechanical energy is used to power the pump. All pumps and motors will have associated piping and fugitive components, which emit VOC and possible H₂S emissions from the material being handled (covered in the total component count under Fugitive Components section). Tier I BACT for facilities of this type are: sealed units, performing fugitive monitoring, preventative maintenance, and appropriate combustion unit limitations.

Emissions from MSS activities were evaluated and found to be of the same character as production emissions. The quantity of fugitive emissions from the repair or replacement of connections was estimated to be the same as purging (covered in the blowdowns section). Maintenance of fugitive components requires purging associated piping and equipment prior to repair or replacement of valves, flanges, and seals. The executive director's staff evaluated small quantities of emissions and small blocked sections of pipelines which are purged prior to maintenance and repair. The applicable BMP and LDAR programs are the same as discussed in Fugitive Components above. Emissions, impacts analysis, and protectiveness review are included with other fugitive component evaluations.

Meters are used throughout OGS and are used by stand-alone Lease Area Custody Transfer (LACT) operations and other processing sites units. Various types of flow measuring instrumentation may be employed to provide accurate information for the amount of product conveyed. Operating emissions from a LACT unit or metering station are normally fugitive in nature and result from piping flange connections, valves, isolation valves, and purging of instrument lines and Tier I BACT currently requires caps on open-ended lines resulting from repairs if open for more than 24 hours. Additional MSS releases occur during repair or maintenance of these components.

C. Separators

A separator is a piece of equipment that separates the production flow stream into gases and liquids. The size of the separator depends on the processing rate of gas and/or liquids in the production flow. The operating pressure of the separator depends on the pressure of the gas pipeline, the flowing pressure of the well, and the operating pressure desired. Separators are built in various designs, including vertical, horizontal, and spherical. Some separators are two-phase separators, which separates the production flow into gas and liquid. Others are three-phase separators, which separate production flow into gas, crude oil, or condensate, and water. Sometimes more than one stage of separation is used to increase natural gas, crude oil or condensate recovery. There were several specific types of separators identified during the executive director's staff evaluation: gun barrels, free-water knockouts, oil/water separators, and membrane units.

1. Gun Barrel Separators: Gun barrel tanks, also known as settling vessels, use gravity to separate the oil from the water. Given enough time, the water will settle at the bottom of the tank and the oil will rise to the top. There are various designs of gun barrels, but the two main types fall into horizontal or vertical designs. They usually are tall enough for gravity flow of the oil out of an outlet in the middle or lower part of the separator into the oil stock tank. The produced water is drawn off the bottom and gas off the top of the separator.
2. Free-Water Knockout Separators: These units are used to separate free gas and water from oil, and emulsions. The size depends on the desired retention time and volume of water to be handled. Time, gravity, mechanical, and sometimes chemical methods, are used to hasten separation in these separators. When heat is needed to separate an emulsion, significant fuel can be saved by using these separators to isolate the emulsion part of the flow instead of a heater being used on the total flow, saving heat, fuel and cost.

3. Oil/Water Separators: Oil/water separators can be electrical (sometimes called electrostatic coalesces or chem-electric treaters) or based on physical insolubility of oil and water. Oil/water separators are normally sealed units with small fugitive component VOC and possible H₂S emissions. Oil/water separators operating or handling low vapor pressure sump or slop oil may be open units with a small tank. The sealed separator may be pressurized. MSS emissions are dependent on the size of the unit and occur when opening the unit for repairs and/or clean out, resulting in VOC and possible H₂S emissions.
4. Membrane Units: Membrane units separate carbon dioxide (CO₂) from natural gas. The membrane units consist of polymers that allow hydrocarbons to pass through the membrane at different rates. The CO₂ membranes produce a high CO₂ concentration stream that may be sent to a pipeline for subsequent processing at another site, vented directly to the atmosphere, or vented indirectly through a control device to the atmosphere. CO₂ membranes produce a high CO₂ concentration stream from a stream of primarily methane and CO₂. Some membrane units may be used in conjunction with one or more amine units or similar units with a different treatment chemical to separate the carbon dioxide and natural gas as an intermediate step or stage of the purification process. The units have thin films of synthetic polymers where smaller or selective gas molecules can pass through increasing concentrations of certain compounds after the membrane. Another absorber solvent, such as an amine treatment unit and several stages of membrane units may be necessary for a production process to produce a high quality CO₂ to meet pipeline specifications. When the high pressure gas does not defuse completely through the membrane it is recycled back to the previous stage as an input. These units have operational and MSS emissions as described in the Amine Treatment section, unless vent gas emissions are recycled to previous stages.
5. For all Separators: During normal production operations, most separators are sealed units with VOC or H₂S emissions through associated valves, flanges, and fittings (fugitive components) and are accounted for in the discussion above. In many locations, gas is sent to an available pipeline for further processing, handling and ultimate sale, resulting in no additional on-site emissions. In a few locations where petroleum liquids are produced and the produced gas flow is very low (or there is no pipeline available) the gas may be flared or released uncontrolled to the atmosphere. In most cases of uncontrolled releases, the VOC released (after subtracting methane and ethane) will not exceed 40 percent of the total release. The dimensions of a separator were characterized as 6 feet long and 2 feet in diameter and may be positioned either horizontally or vertically. Using the Ideal Gas Law, the volume to mass conversion was 481.93 cubic feet (cf)/lb-mole based upon an exit temperature of 200°F. The uncontrolled VOC emissions were estimated as (100,000 cfd) x (0.40) x (1 day/24 hr) x (36 lb/lb-mole) x (1 lb-mole/ 481.93 cf) or 124.50 lb/hr. Tier I BACT for separators is a required control effectiveness of at least 95 percent, or using a pressurized unit and sending streams to another process which is appropriately controlled. When the flow off a separator is sent to a control device, the control device must meet the device requirements established for that system for effective control of emissions. The fugitive VOC and possible H₂S fugitive emissions from any separator are discussed in the Fugitive Components section.

MSS emissions for a separator should be fugitive emissions of VOC and H₂S when the separator is opened for any repair or cleaning. The magnitude of these emissions vary depending on the size of the vessel, the operating pressure, if the pressurized vessel is vented to a control before opening, the amount of material on the wetted inside surface, and the amount of liquids and gases remaining in the separator before opening. Since the separators are commonly pressurized vessels, the uncontrolled degassing activity emissions are most like the dispersion characteristics for blowdowns, and are included in that section. When MSS emissions are sent to a thermal destruction device, the remaining VOC emissions are released at the device's higher temperature, flow rate and stack release height, along with possible sulfur compounds (H₂S converts to SO₂) and products of combustion, and the dispersion characteristics will match that of the control device.

D. Condensers

Condensers are used to liquefy gaseous vapors that are condensable to increase the recovery of VOC compounds and/or reduce downstream loading by removing undesirable materials such as water. These condensers are normally of the air-type, but occasionally water-type condensers are used. At oil and gas sites the only condensers identified with potential air emissions were on amine units and glycol dehydration units, all other condensers appear to be fully contained with no vent to the atmosphere. The process condensers used on amine and glycol dehydration units specifically cool and condense the amine and the glycol so it can be more fully recovered after the reboiler drives off the waste streams. The amines and glycols are very heavy organic chemicals that are easily condensed and the operator has a fiscal desire to retain so they do not need to be replaced. No issues with the minor loss of these compounds at oil and gas sites have been noted to date. In the amine unit, the reboiler drives off the H₂S and CO₂ and any trapped VOCs from the amine and the process condenser is not intended to capture or control these emissions, they are directed to control as appropriate. In the glycol dehydration unit, the reboiler drives off the trapped VOC and H₂S and the specifically attracted BTEX as well as the water the dehydrator was intended to remove; with emissions directed to atmosphere or add-on control as appropriate. The glycol dehydrator is the one unit at oil and gas sites where an add-on control condenser may be used on the waste stream after the process condenser that is returning the glycol to the process. The add-on control condenser will need to direct the condensed water and VOCs to a storage vessel or other wastewater treatment process. The emissions from these add-on condensers are properly evaluated for their control of VOCs by the GRI-GlyCalc program which considers the potential non-saturated state of the VOCs. The glycol dehydration units and their emissions are further addressed below.

Emissions may include VOC (natural gas and condensate groups), BTEX, treatment chemicals, and sulfur compounds (primarily H₂S). In many represented cases in PBR or standard permit registrations, appropriately designed glycol regenerator vents are routed to condensers where the gas streams are compressed and recycled into the plant and the waste streams are sent onto combustion devices or control devices. Consequently, there are no specific emission rates for VOC or sulfur compounds released directly from the condensers listed in the registrations. In addition, limited to no information is available on the usage rates of treatment chemicals (or chemical speciation) that may be used in upstream processing prior to condensation, which may be sent to combustion or control devices.

The condensed streams are not normally pressurized at a production OGS. As such, any MSS emissions for the condenser may be uncontrolled and undirected VOC, treatment chemicals, and possible H₂S fugitive emission from opening the unit for inspection, cleaning and repair. The condenser will typically be drained of any VOC liquids before opening and only a negligible amount of released air contaminants from evaporation of the wetted surface of the inside walls of the unit will be released. Emissions from MSS may be estimated based on the interior surface area of the unit and the characteristics of the material which it previously contained (this method is used for any similar vessel clean-out). The amount of these MSS emissions is a function of the vessel size, operating pressure of the gas stream processed, and concentration of the air contaminants in the gas stream. When MSS emissions are sent to a thermal destruction device, the remaining VOC emissions are released at the device's higher temperature, flow rate and stack release height, along with possible sulfur compounds (H₂S converts to SO₂) and products of combustion, and the dispersion characteristics will match that of the control device.

E. Treatment and Processing

Water vapor in natural gas can form hydrates that are an ice-like sludge under certain conditions. When hydrates form in a gas gathering or pipeline system, total or partial blockage of the system may result. To prevent hydrates from forming in a natural gas processing plant, OGS use one or more of several treatment mechanisms: heating the gas stream to above the hydrate formation temperature; adding an antifreeze agent such as methanol or glycol to reduce the hydrate formation temperature; removing water vapor from the natural gas by use of a glycol dehydration unit; dehydrating the gas using a drying agent such as alumina, silica gel, silicon alumina or a molecular sieve; or refrigeration using heat exchangers (lower the temperature) and expansion (drop the pressure to condense water). Other treatment chemicals may be used at OGS, including but not limited to, corrosion inhibitors, surfactants, and scale inhibitors.

1. Heater Treater: A heater treater is a horizontal or vertical unit for heating an oil and water emulsion to separate and then removing the water and oil and to release any gas that results. They are generally small vessels less than 500 gallons in size for the typical OGS and rated at less than 10 million Btu per hour (MMBtu/hr) for the heat transfer rate from the combustion unit using natural gas, liquid petroleum gas (LPG) or field gas. A typical heater treater may have a combustion unit rated at 0.5 MMBtu/hr. Their main function is to heat the water to break up the water-oil emulsions. They have a very small amount of VOC and possibly H₂S fugitive component emissions for piping associated with the unit. The emissions from the heater treater vent include products of combustion (NO_x, CO, VOC, PM, HCHO, and SO₂) and material handling emissions of VOC and possibly H₂S if the site processes sour crude oil or gas. Products of combustion are evaluated in the Combustion Units Section. Material handling releases are covered under Fugitive Components and should be included in that total count for evaluation.

Tier I BACT for heater treater units is the same BACT for boilers and process heaters. There are no numerical BACT standards for boilers, reboilers, process heaters, and heater treaters with heat inputs less than 10 MMBtu/hr. For boilers, reboilers, process heaters, and heater treaters with heat inputs equal to or greater than

10 MMBtu/hr and less than 40 MMBtu/hr, the BACT emission limit for NO_x is 0.1 lb NO_x/MMBtu. For boilers, reboilers, process heaters, and heater treaters with heat inputs equal to or greater than 10 MMBtu/hr, the BACT emission limit for CO is 0.074 lb CO/MMBtu.

Planned MSS activities anticipated to be associated with heater treaters cannot be further evaluated at this time. The commission does not have sufficient information on the physical design parameters and operational activities which occur at OGS to accurately predict representative emissions from this MSS activity. Based on similar combustion devices, there may be an instantaneous, uncontrolled spike in emissions that occurs for only a portion of the actual hour. Consistent with federal new source performance standards (NSPS) or maximum achievable control technology (MACT) for combustion devices, current TCEQ permit reviews do not require a compliance demonstration for NO_x, CO, or VOC during combustion unit startup. Specific data on this possible spike is scarce. Research by the executive director's staff found data showing that car engines put through the federal emissions tests achieve emissions steady-state operation and controls (if used) are effective after 5 minutes of operation. It is reasonable to project this information to larger combustion units, which might emit at higher levels for 10 – 15 minutes. In the situation where control are used to reduce emissions, with 50 minutes of controlled operation at 90 percent NO_x reduction, and 10 minutes of uncontrolled operation results in an emissions rate for an hour in which startup occurs as 2.5 times the normal hourly emissions.

2. Methanol Injection: Water vapor in natural gas at high pressures and several degrees above the freezing point of water (32°F) can cause serious operating problems by forming gas hydrates, an ice-like sludge. When hydrates form in a gas gathering or pipeline system, total or partial blockage of the system may result. Methanol is injected into the gas stream to prevent hydrate formation. Methanol injection into the gas process stream may result in methanol and additional VOC emissions from downstream processing units during production operations. BACT for Methanol Injection is covered under Fugitives Components and Storage Tanks as applicable. Limited to no information is available on the use of methanol injection for OGS in Texas with respect to quantification of process emissions. Handling of methanol is considered in the section Treatment Chemicals. Maintenance on the piping and pump should result in small methanol fugitive emissions. Maintenance emissions from any methanol storage tank occur consistent with other MSS VOCs from Storage Tanks. The methanol emissions will be consider and reviewed as a treatment chemical. Any MSS emissions resulting from opening the vessels are released and disperse with little or no flow, at ambient temperature, and in an undirected manner.
3. Glycol Dehydrators: A glycol dehydrator is used to remove water from natural gas streams, and to prevent the formation of hydrates and corrosion in the pipeline. These units may have uncontrolled emissions of VOCs and H₂S as well as the treatment chemicals (glycols). In addition to using GRI's GlyCalc program to estimate emissions from the glycol dehydrator, sampling can be performed. A sample of the lean glycol and rich glycol can be obtained, an extended analysis performed on both (must obtain benzene) and a simple mass balance equation can be run to determine the emissions from the reboiler unit. Current Tier I BACT for glycol dehydrator regenerator vents and flash tank vents requires the still vent to be routed to a flare achieving a minimum 98 percent destruction efficiency or to a firebox achieving

a minimum 99 percent destruction efficiency. Appropriate controls are listed in the BMP and BACT requirements and in Table 10. Vapors routed to a fuel gas system or sales gas line shall be considered to be 99 percent controlled. The majority of existing sites reviewed controlled dehydrator emissions, and all were equipped with at least a condenser providing 80 percent control of the BTEX emissions and a reboiler achieving at least 50 percent on-line time, with a combined VOC effectiveness of almost 90 percent. Many of the sites were also equipped to capture the uncondensed vapors from the condenser for use as supplemental fuel. This permit file research also found a representative stack flow rate of 500 actual cubic feet per minute (acfm), 120°F, diameter of 1 foot, with an exit velocity of 10.6 feet per second (ft/s) and heights ranged from 10 feet to 60 feet. Weekly monitoring is not required for glycol dehydration and/or amine units if the worst case combination of parameters resulting in the greatest emission rates is used for emission estimates. Actual measured data is not necessary if worst case data is used. Agency guidance will be created as needed to explain what acceptable worst case parameters are and how they should be obtained

4. Molecular or Mole Sieves: A molecular sieve is a vessel that houses a material containing tiny pores of a precise and uniform size that is used as an adsorbent for gases and liquids. Molecules small enough to pass through the pores are adsorbed while larger molecules are not. Because of this, mole sieves often function as a desiccant. A molecular sieve can adsorb water up to 22 percent of its own weight. Often they consist of aluminosilicate minerals, clays, porous glasses, microporous charcoals, zeolites, active carbons, or synthetic compounds. They are extensively used at natural gas liquid (NGL) recovery and LPG plants for dehydration and in other applications for removal of contaminants, filtration, and separation. Once the desiccant is saturated with liquid it must be “regenerated.” This is accomplished by passing hot, dry gas through the bed to absorb the liquids out of the material. This gas is then condensed and the liquids are separated. Typically, two beds are used one for drying the gas and the other is in the regeneration cycle mode. Normally molecular sieves are regenerated by passing heated dehydrated process gas through the sieve material, after which the gas is normally recycled as an input to a glycol dehydration unit. The normal production emissions are fugitive components and products of combustion (NO_x, CO, VOC, PM, HCHO, and SO₂). Products of combustion from the regeneration cycle are evaluated in the Combustion Units section and material handling releases are covered under Fugitive Components and they should be included in that total count for fugitive emissions and they are evaluated as fugitive components.

Molecular sieves will have a small amount of emissions for MSS whenever the vessel containing the molecular sieve material has to be opened for maintenance operations. Adsorbed gases from the gas stream being processed through the mole sieve material and the gas contained in the vessel will generate emissions when the vessel is opened. Any MSS emissions resulting from opening the vessels containing the mole sieve material for replacement are released and disperse with little or no flow, at ambient temperature, and in an undirected manner. MSS activities associated with these sieves cannot be further evaluated at this time.

5. Amine Sweetening: Sweetening is the general term used to describe the removal of sulfur compounds from gas, crude oil or condensate and the weak acid gas CO₂, from natural gas. Most sweetening units use an amine compound to remove sulfur compounds (primarily H₂S) and from a sour gas. The amine solution has an affinity for sulfur and CO₂, and absorbs it much like glycol absorbs water. In the sweetening process, the gas stream and the liquid amine are contacted in a countercurrent flow in an absorption column. The sour gas to be scrubbed enters at the bottom and the amine solution at the top of an absorption column providing for countercurrent flow over the packed column material. The liquid amine solution containing the absorbed gases exits from the bottom of the column and is sent to a regenerative unit or reboiler to strip the sulfur compounds. There the amine solution is heated and acid gasses are liberated. At this point the amine solution is now a hot and lean amine solution. Some amine solution is carried over in the liberated gas stream and is recovered using a condenser before the stream is released to the atmosphere or sent to an air control such as a flare. The hot lean amine solution then flows through a heat exchanger where it heats the rich amine solution from the absorption column before it is returned as the lean amine solution to the absorption column. Amine units typically also have flash tanks. For Tier I BACT, at a minimum the amine unit regenerator vent and flash tank vent must be routed to a flare, thermal oxidizer, or vapor combustor with a minimum of 98 percent destruction efficiency. Weekly monitoring is not required for glycol dehydration and/or amine units if the worst-case combination of parameters resulting in the greatest emission rates is used for emission estimates. Actual measured data is not necessary if worst-case data is used. Agency guidance will be created as needed to explain what acceptable worst-case parameters are and how they should be obtained.

Different amines have different reaction rates with various acid gases. In addition, amines vary in their equilibrium absorption characteristics with various acid gases, have different sensitivities as to solvent stability, and have different corrosion rates on other materials. Alkanolamines can be divided into three groups: primary amines such as monoethanol amine (MEA) and diglycolamine (DGA); secondary amines such as diethanolamine (DEA) and di-isopropylamine (DIPA); and tertiary amines such as triethanolamine (TEA) and methyl-diethanolamine (MDEA). MEA is the traditional choice for a solvent based upon the highest theoretical amine CO₂ absorption capacity of a solvent which is not realized in practice due to corrosion problems. MEA is the least expensive and has the highest vapor pressure of the alkanolamines solvents. High solvent carryover can occur during CO₂ removal and regeneration. In addition, MEA reacts irreversibly with minor impurities such as carbonyl sulfide (COS) and carbon disulfide (CS₂) resulting in solvent degradation. Foaming of MEA with built-up impurities is a concern. Other amines above going from groups (1) to (3) have lower heat of reaction, lower operating temperatures, lower operating energy requirements and lower steel corrosion rates (due to dissolved CO₂ not necessarily due to the amine). These characteristics are the reason that many custom or proprietary amine solutions are in use.

These sources were reviewed and reasonable worst case parameters were chosen from amine treaters and glycol dehydration units. These vent parameters are thought to be representative of any other kind of stack/vent that is not associated with loading or storage tanks, which have been captured in the “fugitive/loading” category. Stack parameters were derived from a review of PBR and standard permits, and case-by-case NSR permitted sources. A stack flow rate of 500 acfm, a temperature range of 120-200°F, a diameter of 0.25-1 foot, an exit velocity of 10.60 ft/s, and heights ranged from 10 feet to 60 feet were determined to be a reasonable worst case based on a review of permit files.

Methodologies available for calculating emissions were dependent on available data, resources, and the degree of accuracy required in the estimate. Emission estimates from inputs for programs such as the AMINECalc were generally based on the chemical/physical properties of the material involved, operating data, and physical characteristics of the source equipment. When estimating emissions it is essential that correct data are entered into the program. After reviewing the web sites of several amine unit suppliers and attempting to contact many of the suppliers, only limited responses were received by agency staff. The result of the research indicates amine units were installed on a case-by-case basis depending on the plant’s design, production, and the type of control or recovery process needed. In many cases, amine treaters were used in combination with reboilers or heaters, so additional combustion emissions will result (covered in the Combustion Units section). Resulting sulfur emissions will depend on the concentration of the sour materials handled, but if sweet, emissions were expected to be approximately 0.01 lb/hr and no more than 0.02 tpy SO₂. The remaining VOC emissions from the reboilers or heaters ranged from 0.02 lb/hr to 0.05 lb/hr and 0.10 tpy to 0.30 tpy total VOC. In the standard permit which does not represent a combustion unit, only emissions vented directly from the amine treater, processing and flash losses range from 0.75 lb/hr to 1.5 lb/hr and 3.3 tpy to 4.5 tpy VOCs (including treatment chemicals such as DEA). Limited to no information was available on the usage rates or chemical speciation of amine chemicals. Handling of amines is considered in Treatment Chemicals. Atmospheric vessel degassing, maintenance, and startup expectations are the same as listed for separators and dehydrators.

6. H₂S scavenger chemical reaction vessels for sulfur removal are a type of sweetening process for removal of primarily H₂S. The reactant is contained in a vessel and the sour gas is flowed through the vessel until the reactant is spent. Then, the non-hazardous spent reactant is removed and sent to disposal. During normal production operations the only emissions are tank venting of sweetened gas, fugitive component and piping emissions since the reaction occurs in a sealed vessel. VOC, H₂S, and PM₁₀ emissions may result during maintenance for the replacement of the reactant material in the vessels. The pressurized gases contained in the vessel and associated piping will be vented to the atmosphere through a process vent resulting in VOC and H₂S emissions, vented to a thermal destruction where emissions of the products of combustion (NO_x, CO, VOC, PM₁₀, formaldehyde, and SO₂) and H₂S will result, or vented to the atmosphere in an uncontrolled and undirected manner (fugitive dispersion). The magnitude of these emissions should vary depending on

the size of the vessel, the operating pressure, if the vessel is pressurized and vented to a control before opening, the amount of material on the inside, and the amount of liquids and gases remaining before opening. Since some types of these units are commonly pressurized vessels, the uncontrolled degassing activity of these emissions are most like the dispersion characteristics for blowdowns, and are included in that section. When MSS emissions are sent to a thermal destruction device, the remaining VOC emissions are released at the device's higher temperature, flow rate and stack release height, along with possible sulfur compounds (H_2S converts to SO_2) and products of combustion, and the dispersion characteristics will match that of the control device. Atmospheric vessel degassing, maintenance, and startup expectations are the same as listed for separators and dehydrators.

7. Iron Sponge Units: An iron sponge unit is a solid chemical type of sweetening unit. These units are used to remove H_2S from the gas stream. The sour gas stream is routed through pressure vessels or tanks containing iron oxide and wood chips which convert the hydrogen sulfide to water and iron sulfide. Normal production emissions are small amounts of VOC and H_2S fugitive component emissions from a small amount of valves, piping, and connections. Sour gas is sent through a bed of hydrated iron oxide. The subsequent reaction with hydrogen sulfide produces iron sulfides and a small amount of water. Limited or no information is available on the use of iron sponge units and associated iron sulfide emissions.

Planned MSS emissions occur from opening the vessel and replacing the spent iron sponge material. Expected emissions during maintenance would result from de-pressurizing and opening the iron sponge vessel to the atmosphere. The VOC and sulfide emissions, primarily hydrogen sulfide, will result in uncontrolled and undirected emissions (fugitive dispersion). The pressurized gases contained in the vessel and associated piping will be vented to the atmosphere through a process vent resulting in VOC and H_2S emissions, vented to a thermal destruction where emissions of the products of combustion (NO_x , CO, VOC , PM_{10} and SO_2) and H_2S will result, or vented to the atmosphere in an uncontrolled and undirected manner (fugitive dispersion). The magnitude of these emissions vary depending on the size of the vessel, the operating pressure, if the pressurized vessel is vented to a control before opening, the amount of material on the wetted inside surface, and the amount of liquids and gases remaining before opening. Since these units are commonly pressurized vessels, the uncontrolled degassing activity emissions are most like the dispersion characteristics for blowdowns, and are included in that section. When MSS emissions are sent to a thermal destruction device, the remaining VOC emissions are released at the device's higher temperature, flow rate and stack release height, along with possible sulfur compounds (H_2S converts to SO_2) and products of combustion, and the dispersion characteristics will match that of the control device. Atmospheric vessel degassing, maintenance, and startup expectations are the same as listed for separators and dehydrators. Of particular concern with these units is the exposure of the treatment residue to the air and the safety concerns over spontaneous combustion and fire. All reasonable precautions should be taken by operators during maintenance on these units.

8. Treatment Chemicals: Treatment chemicals is the general term used to describe all forms (solid, liquid or gas) of chemical compounds that may be used at an OGS and subsequently emitted from various process equipment. These chemical compounds are commonly used in treatment processes, which include but are not limited to: absorption, adsorption, corrosion inhibition, odorizing, lubrication, cleaning, sweetening, defoaming, emulsion breaking, deicing, and dehydration.

Examples of treatment chemicals are: amine compounds used for sweetening sour gas; amine compounds used as a solvent to separate CO₂ from field gas; glycols used in dehydration units; and methanol used for prevention of hydrate formation. The calculations of specific emissions from these treatment chemicals are difficult and many of the chemicals are proprietary products. The treatment chemical emissions including MSS will exit the OGS through any emission points: fugitive components, loading/filling vents, tanks vents, process vents, and blowdown or flare sources. Storage and receiving of these treatment chemicals is covered in the Storage Tank section. Emissions from the use of these chemicals are covered in the specific treatment process unit section. In general, many treatment chemicals must remain in the system they are injected into in order to perform the function for which they are intended and designed. Many times the amount (surfactants, scale inhibitors, corrosion inhibitors, etc.) used are the smallest concentration possible to reduce cost, as well as reduce the potential of down-stream issues such as “gunking” which can result from over treatment.

Emissions of treatment chemicals from the process should be negligible due to the nature of the chemicals and their use. The only expected quantifiable emissions from treatment chemicals are expected to be from fugitive components during transfer from storage to process unit. If appropriate fugitive monitoring is performed at an OGS based on site-wide VOC quantification, the concentrations of these fugitive component releases is anticipated to be negligible on a species chemical basis.

In other cases, treatment chemicals (for example, glycols and amines) are used in substantial quantities (over 30,000 gallons per year) and during the treatment process may be subject to temperatures above their boiling points. Emissions from these process units, such as reboilers rated at 100 MMBtu/hr, are products of combustion and VOCs from the materials handled and other contaminants which may be selectively absorbed from the gas stream. Most of the recent patents with glycol and amine gas treatment units deal with methods for minimizing emissions of treatment chemicals. Most reboilers should have an air condenser with 80 percent efficiency control and may or may not have further emissions controls on the emission, with larger rated units normally equipped with thermal air control.

EPA has recently announced a major initiative to review and assess the appropriate uses and limitations to fractionation materials and techniques. Since this project is underway at the federal level, the commission has not included any additional analysis or requirements in regards to hydraulic fracturing this package.

F. Cooling Towers

Cooling towers are equipment which through the process of direct contact with atmospheric air, reduce the temperature of water used to cool either process equipment or process fluid streams. Cooling tower heat exchanger system refers to the cooling tower and all associated heat changers, pumps, and ancillary equipment where water is used as a cooling medium to which the heat from process fluids is transferred. Each cooling tower in VOC service is considered a facility and multicell towers are represented as a single facility. Although the predominant contaminants in cooling water are VOCs, dissolved gases such as H₂S and ammonia may also be found. All cooling towers operate such that they may emit PM, dissolved solids, or treatment chemicals entrained in the water emissions fall into three categories: PM, inorganic compounds, and volatile organic compounds (VOCs, which may contain HAPs). Any cooling tower has the potential to emit all three of these emission types in varying amounts, depending on its service.

Particulate emissions result from the presence of minerals or any dissolved or suspended solids in the cooling water. Air flowing through the tower can entrain water droplets and carry them out of the cooling tower in a process referred to as drift. Once these drift droplets leave the tower and evaporate, they deposit dissolved or suspended solids as fine particulate matter (PM₁₀ or smaller). Cooling towers are generally designed with drift eliminators, typically a mesh or series of angled slates placed above the water. No information is available on the emissions of PM₁₀ or PM_{2.5}, although at least one standard permit registration lists 0.05 lb/hr and 0.25 tpy PM from a cooling tower. A review of permits for other sources which use cooling towers that is much larger than those expected at OGS indicate that the PM₁₀ emissions should not be a significant source that requires further review, if the cooling tower is designed with drift eliminators.

Inorganic emissions may result from inorganic process fluids leaking into the cooling water or from water treatment chemicals or other additives used in the cooling water system. The air flowing through the tower may strip these inorganic compounds from the water, resulting in emissions. Typical inorganic emissions may consist of chlorinated compounds, brominated compounds, or any other inorganic substance present in the cooling water. Water treatment chemical emissions also occur, and for purposes of this evaluation, should be estimated and considered similar to all other treatment chemicals. A cooling tower's emission point is typically a stack (varying heights), releasing air contaminants typically in a range close to ambient conditions, with little to no forced flow. Additionally, limited or no information is available on the emissions of inorganic treatment chemicals.

Although some VOC emissions may result from the stripping of organic water treatment chemicals, the primary source of VOC emissions are hydrocarbon-containing process fluids leaked into the cooling water by components of the cooling tower heat exchanger system. Once the hydrocarbon-contaminated cooling water reaches the tower, the VOCs either flash out of the water or are stripped out by the tower's air flow. This may result in many tons of VOC emissions. Based on a representative group of PBR and standard permit files, the amount of VOC varies widely and ranges from <0.10 lb/hr to 5.00 lb/hr and 0.01 tpy to 11 tpy VOC.

Tier I BACT for cooling towers has the requirement to monitor for PM and VOC (including HAPs) emissions and tower designed to reduce drift. For VOCs, cooling tower water should 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 Executive Director. Adequate monitoring requires a periodic sample (daily, weekly, monthly) be taken of the inlet water to the tower to determine VOC concentration. An analysis of the outlet water is sometimes required in order to determine the total amount of VOC (and HAPs) emitted. Limiting the solids buildup in the cooling water indirectly limits the PM emitted from cooling towers, as does a proper operation of the mist eliminators. Tier I minimum acceptable control for PM is the use of mist eliminators and to control PM emissions to ≤ 0.001 percent is based on current industry practice for cooling towers. In non-attainment or near non-attainment counties, other requirements apply to cooling towers, such as 30 TAC Chapter 115, Subchapter H, Division 2, §§115.760 - 796. In these situations, highly reactive VOCs (1, 3-butadiene, isomers of butene [isobutene, 2-methylpropene, isobutylene, alpha-butylene, ethylethylene, beta-butylene, cis- and trans-isomers of dimethylethylene], ethylene, or propylene) have unique requirements. For this proposal, the control of highly reactive volatile organic compounds (HRVOCs) do not trigger a BACT review, and any facility in those particular ozone areas must comply with the 30 TAC Chapter 115 requirements regardless of this PBR or standard permit, although it is not likely that OGS will have these compounds present. The typical and expected federal standards applicable to cooling towers includes: 40 CFR Part 60, NSPS Subpart KKK, Equipment Leaks of VOC from Onshore Natural Gas Processing Plants.

MSS activities associated with these units are based in current industry practice. Faulty equipment shall be repaired at the earliest opportunity but no later than the next shutdown of the process unit in which the leak occurs.

G. Gas Recovery Processes

Several processes are used for natural gas liquid (NGL) recovery and liquid petroleum gas (LPG) plants to recover non-methane hydrocarbons from natural gas.

1. NGL/LPG Cryogenic Expansion: In the cryogenic expansion process, the gas stream is initially treated by low-temperature separation to remove any residual water in the gas. The dehydrated gas is split, and part of the gas is cooled to -25°F using residue gas. The remainder of the gas is chilled to 4°F using propane as the refrigerant. The split streams are combined and enter the high pressure separator where the cold liquid hydrocarbons are separated from the gas. The cold liquid hydrocarbons leave the high pressure separator and are reduced in pressure across a valve to lower the temperature to -45°F . This cold liquid hydrocarbon stream provides the heat sink for the upstream heat exchangers used to chill the incoming gas stream. After passing through these heat exchangers, the warm liquid enters the demethanizer. The gas stream from the high pressure separator is expanded to reduce the temperature to 85°F . This gas stream enters the low pressure separator where the hydrocarbon liquids are separated from the gas. The separated liquid stream is circulated as the coolant in the condenser on the demethanizer column and reintroduced as reflux to the demethanizer. The gas stream from the low pressure separator is used to further cool the overhead stream from the demethanizer, and then combined with the

demethanizer overhead stream. This combined gas stream is compressed to pipeline pressure. Cryogenic plant emissions primarily include exhaust from the compressor driver (covered in the Combustion Units section), flue gas from the demethanizer reboiler, fugitive component emissions (covered in the Fugitive Components section), and emissions from maintenance activities. For VOC in process vents current Tier I BACT requires routing vent streams to a flare, oxidizer, or absorber meeting at least 98 percent effectiveness.

Expected emissions during maintenance would result from depressurizing and opening the vessel to the atmosphere. The VOC and sulfide emissions will result in uncontrolled and undirected emissions (fugitive dispersion). The pressurized gases contained in the vessel and associated piping will be vented to the atmosphere through a process vent resulting in VOC and H₂S emissions, vented to a thermal destruction where emissions of the products of combustion (NO_x, CO, VOC, PM₁₀ and SO₂) and H₂S will result, or vented to the atmosphere in an uncontrolled and undirected manner (fugitive dispersion). The magnitude of these emissions should vary depending on the size of the vessel, the operating pressure, if the pressurized vessel is vented to a control before opening, the amount of material on the wetted inside surface, and the amount of liquids and gases remaining before opening. Since these units are commonly pressurized vessels, the uncontrolled degassing activity emissions are most like the dispersion characteristics for blowdowns, and are included in that section. When MSS emissions are sent to a thermal destruction device, the remaining VOC emissions are released at the device's higher temperature, flow rate and stack release height, along with possible sulfur compounds (H₂S converts to SO₂) and products of combustion, and the dispersion characteristics will match that of the control device. Atmospheric vessel degassing, maintenance, and startup expectations are the same as for separators and dehydrators.

2. NGL/LPG Refrigeration Process: In the conventional refrigeration process, the inlet gas stream is initially contacted with a lean glycol solution to remove water from the gas stream. The gas/glycol stream is chilled to 30° F to separate the condensable liquid hydrocarbons from the dry gas stream. The liquid hydrocarbons are separated from the rich glycol solution and sent to a stabilizer, where the lighter gas stream is separated from the heavier liquid hydrocarbons. The rich glycol stream is regenerated to remove the absorbed water and recycled to the process. Emissions associated with the refrigeration process include the glycol regenerator off-gas. The flue gas stream from the glycol regenerator reboiler is also typically vented to the atmosphere and may be a source of emissions. Other sources of emissions include fugitive component emissions. Emissions may occur from engines or turbines used for compression in the process and from MSS emissions.
3. NGL/LPG Absorption Process: In the absorption process, the wet field gas is contacted with an absorber oil in a packed or bubble tray column. Propane and heavier hydrocarbons are absorbed by the oil while most of the ethane and methane pass through of the absorber. The enriched absorber oil is then taken to a fractionator where the absorbed propane and heavier hydrocarbons are stripped from the oil. The overhead gas product stream from the absorber is then compressed to pipeline pressure. Absorption process emissions include exhaust from the compressor driver (see Combustion Unit section), exhaust gas from the fractionator reboiler, fugitive components (see Fugitive Components section), and vented emissions due to maintenance activities.

4. NGL/LPG Adsorption Process: The adsorption process utilizes two or more molecular sieve beds to absorb all hydrocarbons except methane. The beds are used alternately, with one or more beds on-stream while the others are being regenerated by means of heat or steam which removes the adsorbed hydrocarbons. If steam is used, the steam/ hydrocarbon vapor stream is condensed and liquid hydrocarbons fed to a fractionation process where the various compounds are separated. Emissions associated with the adsorption process primarily include regenerator vent emissions (if any), exhaust emissions from process heaters associated with the regeneration cycle (see Combustion Unit section), MSS emissions, and fugitive components (see Fugitives section).

Normally, the TCEQ sees represented emissions from NGL/LPG refrigeration, adsorption, absorption, or combination of such for only associated process heaters, glycol units, amine units (for CO₂), compressor engines or turbines, piping fugitives, and MSS emissions. Normally, final process vents or streams are represented as residue gas products or natural gas liquids products, not waste gas streams. BACT for process heaters, glycol units, amine units, compressor engines or turbines, fugitives, and MSS is the same as described elsewhere in the background document and as specified in this standard permit. BACT for process vents from NGL/LPG refrigeration, absorption, or combination of such is for sources of emissions that are not otherwise addressed, as specified in this standard permit.

5. Heat Exchangers and Refrigeration Units: Gases are followed by cooling using heat exchangers, and then further cooling by gas expansion or refrigeration dropping the temperature. Initially, water vapor is condensed and removed above the freezing point or hydrate formation temperature. Further cooling by heat exchangers and/or refrigeration units followed by gas expansion well below the freezing point or hydrate formation temperature, specific VOC gases such as butane and propane (LPG) will condense. These heat exchangers may use part or all of the condensed LPG as the cooling medium for cooling the incoming gas stream. These systems are closed systems and have no process vents. Their emissions are from component fugitives so Tier I BACT is historically a LDAR program for fugitives. Limited information is available on the VOC emissions. Planned MSS emissions are released in an undirected manner from opening the pressurized vessel to the atmosphere, except when they are routed to an emission control device, or a pipeline.

H. Combustion Units

Combustion sources at OGS consist of reciprocating engines and/or gas turbines that power compressors and generators. Other combustion sources are small heaters, heater treaters, boilers, and reboilers. The emissions to evaluate from any combustion source are the products of combustion, that is, NO_x, CO, SO₂, PM₁₀, and VOC (including HCHO). Emissions of NO_x are authorized as total NO_x emissions, and are evaluated as NO₂ emissions. For engines, NO₂ to NO_x ratios of 0.2 and 0.5 can be claimed for four-stroke (rich and lean burn) engines and for two-stroke (lean burn) engines, respectively. Formaldehyde (HCHO) is the HAP and is emitted in the greatest quantity from engines and has the lowest effects screening level (ESL); therefore it can be used for the HAPs evaluation.

Planned MSS activities associated with combustion units under Section I cannot be further evaluated beyond what is evaluated in this paragraph. The commission does not have sufficient information on the physical design parameters and operational activities which occur at OGS to accurately predict representative emissions from this MSS activity. Based on similar combustion devices, there may be an instantaneous, uncontrolled spike in emissions that occurs for only a portion of the actual hour. Consistent with federal NSPS and MACT for combustion devices, current commission permit reviews do not require a compliance demonstration for NO_x, CO, or VOC during combustion unit startup. Specific data on this possible spike is scarce. Research by the commission found data showing that car engines put through the federal emissions tests achieve emissions steady-state operation and controls (if used) are effective after about 5 minutes of operation. It is reasonable to project this information to larger combustion units, which might emit at higher levels for 10 – 15 minutes. In the situation where control are used to reduce emissions, with 50 minutes of controlled operation at 90 percent NO_x reduction, and 10 minutes of uncontrolled operation results in an emission rate for an hour in which startup occurs as 2.5x the normal hourly emissions. Only NO₂ is expected to be a pollutant of concern during the startup of combustion devices due to the low one hour NO₂ NAAQS. Shutdown and maintenance should be of no concern for criteria pollutants since maintenance occurs when the device is not running and shutdown is a quick process. Engines at oil and gas handling and production operations are usually 4-stroke engines and the only combustion units with add-on controls for NO_x are expected to be 4-stroke rich burn engines. Lean burn startup is on the order of minutes. Since NO_x is a product of high temperature, one would expect a lean burn startup to emit less NO_x than normal operation. A rich burn engine operates under the same concept however the engine may be warm and past startup but the catalyst is not ready yet and so NO_x is higher than normal operation. The NO₂ to NO_x ratio of 0.2 for rich burn engines times the spike at startup (2.5 x) yields a startup hour value of 0.5 of the total normal NO_x emissions as NO₂ during startup. After reviewing Tables 5A-5F, no one engine would be expected to create a NAAQS issue and multiple engines can have a staggered startup schedule if enough engines are on site to create a potential NAAQS issue. Additionally, the commission expects transitional and incidental spikes in emissions of CO and NO_x due to MSS to actually only last a few minutes for uncontrolled engines, turbines, boilers, reboilers, process heaters, and heater treaters; therefore, the commission believes that emissions rates authorized for normal operations of these combustion units also accounts for MSS emissions from these combustion units. There are no reasonable controls to be applied during startup and shutdown of combustion units, so BACT is to minimize the number and duration of startups and shutdowns. Control of blowdowns from non-combustion sources are discussed below.

Emissions from planned MSS due to shutdown and startup of combustion units should not result in any quantifiable hourly emissions change from standard operation of the combustion units with regard to emissions of CO or NO_x. Although there may be transitional and incidental spikes before units stabilize during start-ups (5-15 minutes), overall products of combustion are expected to be within hourly range limits for normal loads during production operations. There are no reasonable controls to be applied during startup and shutdown of combustion units so BACT is to minimize the number and duration of startups and shutdown. Control of blowdowns from associated piping and vessels in petroleum service will be discussed later.

1. Boilers, Reboilers, Heaters and Heater Treaters: Boilers and heaters can vary from a rating of a few thousand Btu/hr for a small heater in a heater treater to large heaters with a rating up to 100 MMBtu/hr or more for heating a gas stream. Most heaters at OGS are less than 40 MMBtu/hr limit and would qualify for PBR §106.183. There are some larger boilers, greater than 40 MMBtu/hr operated and authorized at OGS under standard permits or a new source review permit. BACT for CO is 100 ppmv based on assumptions of complete combustion and standard design of units available in the market today. The requirements are the same as 30 TAC §106.183 Boilers and reboilers with a maximum firing rate greater than 40 MMBtu, should be controlled to 0.04 MMBtu/hr for NO_x and 50 ppmv for CO corrected to 3 percent O₂ when firing natural gas. This is Tier I BACT and has been the accepted control in past permit reviews for the same process/industry for many years, and technical practicability and economic reasonableness have already been demonstrated. This is also consistent with BACT established with the Air Quality Standard Permit for Boilers. Tier I BACT for heater treater units are the same BACT for boilers and process heaters, including: (1) capacity less than 40 MMBtu/hr, meet the technical requirements of 30 TAC §106.183 and less than 0.1 lbs NO_x/MMBtu for heat input greater than 10 MMBtu/hr; (2) capacity equal to or greater than 40 MMBtu/hr, meet 0.01 lb NO_x/MMBtu when firing 75 percent-100 percent natural gas; 0.015 lb/MMBtu when firing plant fuel gas, 50 parts per million by volume dry (ppmvd) CO at 3 percent O₂, 10 ppmvd NH₃ at 3 percent O₂, and have less than 5 percent opacity; process heaters less than or equal to 500 MMBtu/hr meet 0.01-0.036 lb NO_x/MMBtu and 50-100 ppmvd CO at 3 percent O₂; and process heaters greater than 500 MMBtu/hr meet 0.01 lb NO_x/MMBtu when firing 75 percent-100 percent natural gas and 0.015 lb NO_x/MMBtu when firing plant fuel gas, and 50-100 ppmvd CO at 3 percent O₂.

Boilers, reboilers, process heaters, and heater treaters heaters can vary from heat inputs of a few thousand Btu/hr up to 100 MMBtu/hr or more. Most reboilers, process heaters, and heater treaters at OGS have heat inputs that are much less than 40 MMBtu/hr limit and could qualify for PBR §106.183. There are some larger boilers, greater than 40 MMBtu/hr operated and authorized at OGS under standard permits or a new source review permits.

Natural gas, field or fuel gases are the typical fuels used for boiler, reboilers, process heaters, and heater treaters associated with the handling and production of oil and gas. There are no numerical BACT standards for boilers, reboilers, process heaters, and heater treaters with heat inputs less than 10 MMBtu/hr. For boilers, reboilers, process heaters, and heater treaters with heat inputs equal to or greater than 10 MMBtu/hr and less than 40 MMBtu/hr, the BACT emission limit for NO_x is 0.1 lb NO_x/MMBtu. For boilers and reboilers with heat inputs greater equal to or greater than 40 MMBtu/hr, the BACT emission limit for NO_x is 0.036 lb NO_x/MMBtu. For process heaters and heater treaters with heat inputs equal to or greater than 40 MMBtu/hr and less than 100 MMBtu/hr, the BACT emission limit for NO_x is 0.06 lb NO_x/MMBtu. For process heaters and heater treaters with heat inputs greater than 100 MMBtu/hr, the BACT emission limit for NO_x is 0.036 lb NO_x/MMBtu. For boilers, reboilers, process heaters, and heater treaters with heat inputs equal to or greater than 10 MMBtu/hr, the BACT emission limit for CO is 0.074 lb CO/MMBtu.

There are no standards for VOC, PM₁₀, PM_{2.5}, and SO₂, and HAPs emissions from the combustion devices under Section I; proper operation and good combustion is necessary to meet the BACT emission limits for CO and NO_x or to minimize the waste of fuel, and proper operation and good combustion ensures good destruction of VOCs, including HAPs, and H₂S (yielding SO₂ emissions) and minimization of PM₁₀ and PM_{2.5} emissions. The formation of HAPs due to combustion in boilers, reboilers, process heaters, and heater treaters is small based on available information. The BACT emission limits for boilers, reboilers, process heaters, and heater treaters have been acceptable BACT emission limits in past permit reviews for the oil and gas handling and processing operations, and technical feasibility and economic reasonableness have already been demonstrated for the BACT emission limits. Problems are not expected with existing boilers, reboilers, process heaters, and heater treaters being able to comply with the BACT emission limits.

Boilers and reboilers with maximum firing less than 40 MMBtu should easily meet the 0.10 lb NO_x/MMBtu/hr BACT requirement when firing natural gas. The requirements are the same as 30 TAC §106.183,. Boilers and reboilers with a maximum firing rate greater than 40 MMBtu, should be controlled to 0.04 MMBtu/hr for NO_x and 50 ppmv for CO corrected to 3 percent O₂ when firing natural gas.

Planned MSS activities anticipated to be associated with combustion units cannot be further evaluated at this time. The commission does not have sufficient information on the physical design parameters and operational activities which occur at OGS to accurately predict representative emissions from this MSS activity. Based on similar combustion devices, there may be an instantaneous, uncontrolled spike in emissions that occurs for only a portion of the actual hour. Consistent with federal NSPS and MACT for combustion devices, current TCEQ permit reviews do not require a compliance demonstration for NO_x, CO, or VOC during combustion unit startup. Specific data on this possible spike is scarce. Research by the executive director staff found data showing that car engines put through the federal emissions tests achieve emissions steady-state operation and controls (if used) are effective after about 5 minutes of operation. It is reasonable to project this information to larger combustion units, which might emit at higher levels for 10 – 15 minutes. In the situation where control are used to reduce emissions, with 50 minutes of controlled operation at 90 percent NO_x reduction, and 10 minutes of uncontrolled operation results in an emissions rate for an hour in which startup occurs as 2.5 times the normal hourly emissions.

2. Reciprocating Engines and Turbines: Reciprocating engines can be either rich-burn or lean-burn based upon the oxygen content in the exhaust of the engine and the majority at OGS tends to be spark ignition. Rich-burn engines need to use a catalytic converter to meet the 2.0 - 0.5 g NO_x/hp-hr Tier I BACT.

Reciprocating engines and turbines can be either rich-burn or lean-burn based upon the oxygen content in the exhaust of the engine or can be dual fuel fired or liquid fired, and the majority at OGS tend to be spark ignition. There are no standards for emergency engines. Engines for power generation are addressed under paragraph (e), Best Management Practices.

Unless otherwise specified in the standard permit for oil and gas, emission limits for lean-burn, rich-burn, dual fuel fired engines, and turbines is listed in Table 6 of the standard permit.

New and modified spark-ignited rich-burn engines need to use a catalytic converter to meet the emission limits of 0.5 g NO_x/hp-hr which is the BACT emission limit for NO_x for spark-ignited rich-burn engines that are equal to or greater than 100 hp in size. The CO BACT emission limit for spark-ignited rich-burn engines that are equal to or greater than 100 hp in size and manufactured before January 1, 2011 is 3 g CO/hp-hr. There are no standards for VOC emissions for spark-ignited rich burn engines manufactured before January 1, 2011. The BACT emission limits for CO and VOC for spark-ignited rich-burn engines equal to and greater than 100 hp in size and manufactured on or after January 1, 2011 are 3 g CO/hp-hr and 1 g VOC/hp-hr. There are no standards for spark-ignited rich-burn engines less than 100hp in size. The previous PBR §106.512 had no NO_x emission limits for engines less than 500 hp in size, had no emission limits for VOCs, and had no emission limits for CO. The standard permit has schedules for transition from current BACT requirements for NO_x to the new BACT emission limits for NO_x for spark-ignited rich-burn engines. Problems are not expected with compliance with the new BACT requirements for CO and VOC because rich burn engines will use a three way catalyst that controls CO and VOC very effectively. The new BACT emission limits may or may not be as stringent as federal rules and other state of Texas rules, such as 30 TAC Chapter 117. The cost of BACT is discussed below.

New and modified four-stroke spark-ignited lean-burn engines and dual fuel-fired engines are designed to produce less NO_x and can meet the BACT emission limit for NO_x of 1 g NO_x/hp-hr for such engines equal to or greater than 500 hp in size and manufactured on or after July 1, 2010, and most such existing engines equal to or greater than 500 hp in size can meet or are capable of meeting the BACT emission limit for NO_x of 2 g NO_x/hp-hr without using add-on controls for any such engine manufactured before July 1, 2010. The CO BACT emission limit for spark ignited four stroke lean burn engines and dual fuel-fired engines is 3 g CO/hp-hr for any such engine equal to or greater than 500 hp in size and for any such engine less than 500 hp in size and manufactured on or after July 1, 2008. The VOC BACT emission limit for four stroke spark ignited lean burn engines and dual fuel-fired engines is 1 g VOC/hp-hr for any such engine less than 500 hp in size and manufactured on or after July 1, 2008 and for any such engine equal to or greater than 500 hp in size manufactured on or after July 1, 2010. There are no standards for four stroke sparks ignited lean burn engines and dual fuel-fired engines manufactured before July 1, 2008. There are no VOC standards for four stroke sparks ignited lean burn engines and dual fuel fired engines greater than 500 and manufactured before July 1, 2010. The previous PBR §106.512 had no NO_x emission limits for engines less than 500 hp, had no emission limits for VOCs, and had no emission limits for CO. The standard permit has schedules for transition from current BACT requirements for NO_x to the new BACT requirements for NO_x for spark-ignited rich-burn engines. The new BACT emission limits may or may not be as stringent as federal rules and other state of Texas rules, such as 30 TAC Chapter 117. Problems are not expected with compliance with the new BACT requirements for CO and VOC because lean burn engines operate with very high exhaust oxygen which does not favor the formation of CO or VOC. The new BACT emission limits may or may not be as stringent as federal rules and other state of Texas rules, such as 30 TAC Chapter 117. The cost of BACT is discussed below.

New and modified spark ignited two stroke lean burn engines equal to or greater than 500 hp must meet BACT emission limits for NO_x ranging from 1 g NO_x/hp-hr to 8 g NO_x/hp-hr, and the limits vary based on the manufacturer date of the engine. The BACT emission limits for NO_x and the manufacturer dates are listed in Table 6 in the standard permit. The BACT emission limit for CO for spark-ignited two stroke lean burn engines is 3 g CO/hp-hr. The BACT emission limit for VOC for spark ignited two stroke lean burn engines is 1 g/hp-hr for any such engine manufactured on or after July 1, 2010. There are no VOC standards for spark ignited two stroke lean burn engines manufactured before July 1, 2010. There are no standards for spark ignited two stroke lean burn engines less than 500 hp. The previous PBR §106.512 had no NO_x emission limits for engines less than 500 hp, had no emission limits for VOCs, and had no emission limits for CO. Problems are not expected with compliance with the BACT standards for NO_x, CO, and VOC, as the BACT emission limits for NO_x, CO, and VOC for such engines was and is already well established. Therefore, the commission determines that the cost of BACT for such engines does not need to be discussed in further detail in the standard permit background documents.

Additionally, there are no BACT emission limits for HAPs, PM₁₀, or PM_{2.5} emissions from the rich and lean burn engines discussed above, and the commission determines that no BACT emission limits for such are necessary. In general, BACT for engines can be found through:

www.tceq.texas.gov/permitting/air/guidance/newsourcereview/engine/nsr_fac_engine.html and

www.tceq.state.tx.us/permitting/air/nav/air_bact_combustsources.html.

Since the available control technologies for rich burn engines versus lean burn engines are drastically different in cost, the TCEQ Executive Director has created schedules for when each type of engine must meet the lower NO_x standards. Rich burn engines typically are upgraded to meet 0.5 g/hp-hr by the use of advanced air to fuel ratio controllers and additional 3-way catalyst modules which are mostly capital cost items. This is within the range of economic reasonableness the executive director uses in BACT determinations. A typical 500 hp rich-burn engine being controlled from the current §106.512 limit of 2.0 g/hp-hr to the BACT limit of 0.5 g/hp-hr would prevent over 7 tpy of NO_x from entering the atmosphere. Another option for these rich-burn engines is to be converted into lean-burn engines. Conversion is typically less costly than extra controls on existing rich burn engines due to the fuel savings that results from lean-burn operation. The commission is considering balancing the cost of upgrading a large number of engines throughout the state with the ease of upgrading, existing engines.

Lean burn engines represent a harder to control class of engines due to the nature of the exhaust composition. 3-way catalysts require relatively little oxygen in the exhaust to properly oxidize CO and VOC while reducing NO_x. Lean burn engines have too much oxygen in the exhaust for NO_x reduction to occur.

The available options for these engines are retrofitting them with newly designed components that would cause less NO_x production or replacing the engine with a newer model that produces less NO_x. Retrofits are relatively inexpensive but may not apply to all engines. The TCEQ has examined the cost of replacing the engine in order to perform the BACT analysis. While not all engines require replacement, it represents the last available option for control which encompasses all engines in the field.

www.tceq.state.tx.us/permitting/air/guidance/newsourcereview/engine/nsr_fac_engine.html and www.tceq.state.tx.us/permitting/air/nav/air_bact_combustsources.html.

The commission determines the following for compression ignition engines: compression ignition engines that are rated less than 225 kW (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 is BACT for such engines, and such engines can be authorized under the standard permit. (Compression ignition engines are addressed in Paragraph (f)(2)(G) of the oil and gas standard permit.)

BACT for turbines is to operate with low NO_x combustors and meet 25 ppmvd at 15 percent O₂ for NO_x and 50 ppmvd at 15 percent O₂ for CO.

Since the available control technologies for spark-ignited rich burn engines versus lean burn engines are drastically different in cost, the commission has created schedules for when each type of engine must meet the lower NO_x standards. Rich burn engines typically are upgraded to meet the BACT emission limit of 0.5 g NO_x/hp-hr by the use of advanced air to fuel ratio controllers and additional 3-way catalyst modules which are mostly capital cost items. These controls are readily available, easily installed, and according to TCEQ research by the commission, the costs are approximately \$2000 per ton of NO_x controlled. This is within the range of economic reasonableness the executive director uses in BACT determinations. A typical 500 hp rich-burn engine being controlled from the current §106.512 limit of 2.0 g/hp-hr to the BACT limit of 0.5 g/hp-hr would prevent over 7 tpy of NO_x from entering the atmosphere. An uncontrolled 100 hp engine would emit about an additional 9 tpy of NO_x compared to one controlled under this standard permit. Another option for these rich-burn engines is to be converted into lean-burn engines. Conversion is typically less cost costly than extra controls on existing rich burn engines due to the fuel savings that results from lean-burn operation. The commission considers balancing the cost of upgrading a large number of engines throughout the state with the ease of upgrading, existing engines. Therefore, the commission determines that all spark-ignited rich burn engines greater than 100 hp must have emissions standards for NO_x based on BACT. However, engines greater than or equal to 240 hp shall have until January 1, 2015 to meet BACT and engines greater than or equal to 100 hp but less than 240 hp shall have until January 1, 2018 to meet BACT. Engines authorized after the previous dates will have one year to meet BACT. Catalyst controls may be needed to meet the specified BACT emission limits for CO and VOC for spark-ignited rich-burn engines. The commission believes that there will be no problems with compliance with the CO and VOC emission limits, as the commission believes that BACT for NO_x is the driver for additional cost.

Lean burn engines represent a harder to control class of engines due to the nature of the exhaust composition. Three-way catalysts require relatively little oxygen in the exhaust to properly oxidize CO and VOC while reducing NO_x. Lean burn engines have too much oxygen in the exhaust for NO_x reduction to occur. The available options for these engines are retrofitting them with newly designed components that would cause less NO_x production or replacing the engine with a newer model that produces less NO_x. Retrofits are relatively inexpensive (much less than \$5,000 per ton of NO_x controlled as discussed below for replacement of engines) but may not apply to all engines. The TCEQ has examined the cost of replacing the engine in order to perform the BACT analysis. While not all engines require replacement, it represents the last available option for control which encompasses all engines in the field. Controlling a lean burn engine to the BACT emission limit of 2.0 g NO_x/hp-hr may represent a reasonable control cost for engines that emit more than 2.0 g NO_x/hp-hr. Additionally, the newest engines being manufactured emit less than 1.0 g NO_x/hp-hr and it is anticipated that engines will be replaced with these new ultra lean burn models. The commission has determined that the cost of BACT is between \$5,000 and \$10,000 per ton of NO_x controlled; this cost determination includes the commission's belief that the engines that are replaced still have value and can be sold or used elsewhere. Additionally, the newest engines being manufactured emit less than the BACT limit of 1.0 g NO_x/hp-hr and it is anticipated that engines will be replaced with these new ultra lean burn models. If one follows a typical Tier III BACT analysis, the calculated annualized control costs may be economically reasonable especially considering the life of a new engine (which is the control device also) would far exceed the 10 years normally assumed for control device life in Tier III analyses. However, the commission understands that the prevalent use of these engines as a workhorse within the industry may cause undue financial burden on companies with large numbers of engines that would need to be replaced to meet more stringent limits. Therefore, the commission determines that a replacement schedule is appropriate for 4 stroke lean burn engines greater than 500 hp. There are no NO_x standards for all spark ignited lean burn engines less than 500 hp and manufactured before July 1, 2008 because the commission did not identify any group within this category and is under the belief that rich burn engines dominate this category.

I. Storage and Transfer

Many OGS include: condensate tanks, crude oil tanks, slop/sump oil tanks, pressurized tanks for LPG, speciated (separated by process, e.g., butane, propane, etc.) gas tanks, produced water tanks, amine tanks, glycol tanks, treatment chemical tanks, and fuel storage tanks. Storage tanks used at OGS for condensate, crude oil, slop/sump oil, produced water tanks, fuel storage tanks, LPG pressurized tanks and speciated gases found from the permits and registrations reviewed were predominately the fixed roof type tanks with un-insulated exterior surfaces which varied from white to rust colored, and had excellent to very poor paint conditions. The executive director's staff found information in several current permits, standard permits and PBRs that a typical site would include three crude, one condensate, and one or more water tanks. Larger sites have larger fixed roof tank capacities and may have internal or external floating roof tanks.

These findings were also confirmed in an earlier protectiveness evaluation of Standard Exemption 66 conducted in 1997, where it was found that OGS tanks were typically 500 barrel (21,000 gallon) fixed roof storage tanks with a maximum throughput of 500 barrels per day. Fixed roof tanks with internal floating roofs (IFR) were found, along with some external floating roof (EFR) tanks. Both IFR and EFR tanks have lower working and standing emission losses compared to fixed roof tanks without controls so fixed roof tanks were evaluated, representing a worst case scenario for protectiveness review.

Emissions during MSS from various ambient and pressure tanks may include degassing, deheeling, cleaning, and refilling, as well as any other potential air emissions from cleaning, inspection, or repairs associated with planned MSS and will vary based on the operations and physical parameters of any given tank. Since the remaining liquids and gases in atmospheric tanks will be released with no flow rate through existing vents, these emissions should be quantified based on the draining mechanism, physical size of the interior of the tank, and the dispersion characteristics are most like pipeline release emissions. For pressurized tanks, the remaining liquids and gases in the tank will be released with a flow rate through existing vents and these emissions should be quantified based on the draining mechanism and physical size of the interior of the tank. The dispersion characteristics and the pressure of releasing seals for pressurized tanks are most like pipeline or compressor blowdowns. These emissions may be captured, recovered, controlled, or emitted to the atmosphere in an undirected manner.

Based on the commission's evaluation of actual site conditions and input from stakeholders, many OGS have open-topped tanks and ponds which are integral to site operations. In appropriate situations, these open tanks and ponds are acceptable and will only contribute in a negligible way to the site's emissions. In other cases, the amount of hydrocarbon liquids entrained in open-topped tanks and ponds may be sufficient to potentially result in a substantial amount of VOCs and H₂S emissions as the open-topped tanks or ponds are exposed to the evaporative effects of the sun and wind. Therefore, some reasonable limit is considered above which closed tanks are necessary.

1. Crude Oil and Condensate Tanks: Storage tank VOC emissions from crude oil and condensate should be estimated by accounting for Working, Breathing or Standing, and Flash Losses. There are a variety of methods for estimating these emissions and the specifics can be found at:
www.tceq.state.tx.us/permitting/air/announcements/nsr_announce_9_30_09.htm

Tank color plays an important role in accelerating or minimizing VOC emissions from tank working and breathing losses. An estimate of emissions from working and breathing losses was calculated using Tanks 4.0 and based on the same tank with the same characteristics and throughput, only changing the color of the tank. A typical 500 barrel (bbl) fixed roof crude oil tank painted white (which has a reflective heat effect) has the potential to emit 1.26 tpy of VOC. The same tank was then represented as being brown (such as covered in rust to dirt), and the thermal heat transfer to the contents would result in a potential of 2.19 tpy of VOC, or 74 percent greater emissions. In other words, a 43 percent reduction of VOC emissions would occur from changing a brown tank to white.

An additional demonstration was performed to evaluate the effect of color choice on the emissions from a process vessel, such as a storage tank. The Tanks 4.0 program was used to illustrate the effect of color choice on the working and breathing emissions of VOC, benzene and H₂S from a typical oil and gas site condensate storage tank. The H₂S and benzene compositions are representative of common permit submittals. While the emissions from flashing within the tank can be of great significance, these emissions are more greatly affected by changes in pressure than temperature. Therefore, emissions from flashing were not represented in this illustration. The conditions of the Tanks 4.0 program were set as follows:

Shell Height: 15ft
 Diameter: 10ft
 Liquid Height: 15ft
 Avg. Liquid Height: 8ft
 Volume: 8,813 (gallons)
 Turnovers: 365
 H₂S: *0.044 Weight percent

Net Throughput: 3,216,745 (gallons/year)
 Paint Characteristics: See Table Below
 Roof Characteristics: Default
 Breather Vent Settings: Default
 Component: Petroleum Distillate RVP 7
 Site Locations: Dallas, Texas
 Benzene: **0.013 Weight percent

Tank Color	Condition	Solar Absorbance Ratio	Total Emissions	H ₂ S	Benzene	Emission Increase from "White-Good"
White	Good	0.17	2.87 tpy	1.3E-3 tpy	3.7E-3 tpy	
White	Poor	0.34	3.12 tpy	1.4E-3 tpy	4.1E-3 tpy	9%
Specular Aluminum	Good	0.39	3.19 tpy	1.4E-3 tpy	4.1E-3 tpy	11%
Specular Aluminum	Poor	0.49	3.35 tpy	1.5E-3 tpy	4.4E-3 tpy	17%
Light Gray	Good	0.54	3.43 tpy	1.5E-3 tpy	4.5E-3 tpy	20%
Light Gray	Poor	0.63	3.58 tpy	1.6E-3 tpy	4.6E-3 tpy	25%
Diffuse Aluminum	Good	0.60	3.53 tpy	1.6E-3 tpy	4.6E-3 tpy	23%
Diffuse Aluminum	Poor	0.68	3.66 tpy	1.6E-3 tpy	4.8E-3 tpy	28%
Medium Gray	Good	0.68	3.66 tpy	1.6E-3 tpy	4.8E-3 tpy	28%
Medium Gray	Poor	0.74	3.77 tpy	1.7E-3 tpy	4.9E-3 tpy	31%
Primer Red	Good	0.89	4.04 tpy	1.8E-3 tpy	5.3E-3 tpy	41%
Primer Red	Poor	0.91	4.08 tpy	1.8E-3 tpy	5.3E-3 tpy	42%

* (H₂S emissions were calculated by multiplying the total emissions by the weight percent shown.)

** (Benzene emissions were calculated by multiplying the total emissions by the weight percent shown.)

While the argument has been made that solar absorption may not make a significant contribution to the amount of emissions from a process vessel or storage tank, the results clearly demonstrate the paint color used is significant for emissions from working and breathing. Furthermore, painting tanks with a low solar absorption rated color such as white will result in a significant cumulative reduction in statewide emissions of H₂S, benzene, and total VOCs. This has state-wide implications especially for counties currently in nonattainment areas or near-nonattainment areas and those of high urbanization. These results are consistent with the TCEQ Air Permits Division Chemical Sections' previous BACT and BMP determinations for approximately 20 years.

In order to ensure air quality, all facilities authorized must minimize emissions to the greatest reasonable extent, thus the commission has considered included requirements to address color for all permanent and temporary liquid and gas tanks and vessels. To effectively minimize the generation of air contaminants, tank color should be white or reflective because potential emissions from any storage or process tank are directly proportional to its color. Tanks need to be painted white or an equivalent reflective color if emissions are more than 5 tpy. Since the solar absorbance of the paint needs to reduce working and breathing (or standing) losses by 40 percent that would result in a loss of approximately 2 tpy. One estimate submitted by stakeholders claimed as much as \$20,000 for the one-time refinishing and repainting a tank. This would meet the standard BACT determination of \$10,000 per ton of VOC.

Storage tank vent dispersion parameters assume a pipe diameter of 2 inches (0.17 ft), an exit velocity based on volume of flow through the tank, and an exit temperature based on the maximum liquid surface temperature (95°F).

All tanks processing liquids (crude, condensate and water) will also have flash emissions when a liquid goes from a higher pressure to a lower pressure, typically atmospheric pressure and a higher temperature to a lower temperature, typically ambient temperature. As the pressure on the liquid drops the lighter hydrocarbon compounds dissolved in the liquid are released or flashed off from the liquid. Additionally, some of the compounds that are liquids at the initial pressure and temperature entering the tanks transform from a liquid into a gas/vapor, and are also released or flashed from the liquid. As these gases are released, some of the heavier hydrocarbon compounds in the liquid may become entrained in these gases and will be emitted. The magnitude of the flash gases will increase as the magnitude of the pressure and temperature drop increases, and the amount of lighter hydrocarbons found in the liquid increases. Also, the temperature of the liquid and the storage tank will also influence the amount of flashing losses since the ability of a solution to dissolve or hold a gas is related to temperature. If the final temperature is lowered, the final solution can hold more gas which will result in slightly lower flash gas emissions, however if the temperature upon entering the tank is closer to that of the separator, more flash will occur. Consequently, the estimation of flash gas losses becomes a complex process when considering all measured and theoretical properties of the fluids.

Historically, the emission estimates for most OGS tanks have only represented working and breathing or standing losses. However, there are three types of emissions associated from storage tanks used in OGS production processes, flash, working and breathing losses. All OGS processing liquids where the liquid experiences a drop in pressure such as the drop in pressure from a separator to a tank will have flash gas emissions.

Recently, technology improvements in infrared (IR) camera technology allow the direct viewing of VOC emissions. A project during the TexAQS II air quality study used this technology and has provided better awareness of the flash gas emission issues to the executive director. The Air Quality Research Project H51C study used the direct approach to quantify flash gas emissions, as described in *VOC Emissions from Oil and Condensate Storage Tanks, Final Report*, by Albert Hendler, et al, published October 31, 2006. This study attempted to determine an emission factor for flash emission from crude oil and condensate tanks in pounds of flash gas per barrel of production under normal operating conditions from 11 crude oil and 22 condensate tank batteries. The report shows a large variation in measured emissions factors (1 to 215 pounds per barrel) based on a limited number of sample tank batteries (33) from three areas of Texas: Dallas/Fort Worth; Houston/Galveston/Brazoria; and Beaumont/Port Arthur. The report concluded that flash emissions are under reported in emission inventory and permitting.

Due to the large variation of crude and condensate properties throughout Texas, and from site to site, the commission is requiring site specific or defined representative measurements be taken to estimate flash emissions for permitting purposes. To date, EPA published guidance on flash gas emission determination is that direct measurement techniques provides the most accurate results, but the EPA has no standardized published reference test methods available at this time. The commission has published guidance on the preferred methods for estimating representative emissions from OGS Tanks:

www.tceq.state.tx.us/assets/public/comm_exec/pubs/rg/rg360/rg-360-06/techsupp_6.pdf

and

www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/guidance_flashemission.pdf.

Two common systems used at OGS are VRSs and flares. Properly sized, designed, and operated VRSs can achieve 95-100 percent recovery and allow only minor amounts of VOC to escape through fugitive components of the piping. When the VRS is down for maintenance (historically represented as less than 5 percent of the year or 430 hours), tank and vessel emissions are released to the atmosphere uncontrolled. Flares are often used, but destroy VOCs instead of recover them. If flares are properly designed, maintained, and stay lit they achieve 98 percent or better control. When a flare is down for maintenance, tank and vessel emissions are released to the atmosphere uncontrolled.

2. Produced Water Tanks: Produced water is any water trapped in underground formations that is brought to the surface along with oil and gas. However, a well which has been deemed absent of crude oil or condensate (also known as dry) does not necessarily imply that hydrocarbons are not still entrained in the produced water. Produced water is by far the largest volume byproduct or waste stream associated with OGS.

In subsurface formations, naturally occurring rocks are generally permeated with fluids such as water, oil, or gas (or some combination of these fluids). These less dense hydrocarbons migrate to trap locations, displacing some of the water from the formation and become hydrocarbon reservoirs. Thus, reservoir rocks normally contain both petroleum hydrocarbons (liquid and gas) and water. Sources of this water may include flow from above or below the hydrocarbon zone, flow from within the hydrocarbon zone, or flow from injected fluids and additives resulting from production activities. This water is frequently referred to as “connate water” or “formation water” and becomes produced water when the reservoir is tapped and these fluids are brought to the surface.

The composition generally includes a mixture of either liquid or gaseous hydrocarbons, produced water, dissolved or suspended solids, produced solids such as sand or silt, and injected fluids and additives that may have been placed in the formation as a result of exploration and production activities such as hydraulic fracturing.

As produced water is brought to the surface it is separated from the crude oil and natural gas during the production and separation process. The composition of this produced fluid is dependent on whether crude oil or natural gas is being produced and generally contains a mixture of aromatic hydrocarbons such as benzene, toluene, ethylbenzene, and xylene, in addition to other volatile organic compounds. When the produced water flows from the separator into the storage tank, most of the hydrocarbons will either float to the top of the tank or partially dissolve in the water. The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geological formation with which the produced water has been in contact for thousands of years, and the type of hydrocarbon product being produced. Produced water properties and volume can even vary throughout the lifetime of a reservoir. If water flooding operations are conducted, these properties and volumes may vary even more dramatically as additional water is injected into the formation.

Knowledge of the constituents of specific produced waters is needed for regulatory compliance. Oil and grease are the constituents of produced water that receive the most attention in both onshore and offshore operations, while salt content (expressed as salinity, conductivity, or total dissolved solids) is a primary constituent of concern in onshore operations. In addition, produced water contains many organic and inorganic compounds which can be in a variety of physical states including solution, suspension, emulsion, adsorbed particles, and particulates.

In addition to its natural components, produced waters from oil production may also contain groundwater or seawater (generally called “source” water) injected to maintain reservoir pressure, as well as miscellaneous solids and bacteria. Most produced waters are more saline than seawater. They may also include chemical additives used in drilling and producing operations and in the oil/water separation process. In produced water, these chemicals can affect the oil/water partition coefficient, toxicity, bioavailability, and biodegradability.

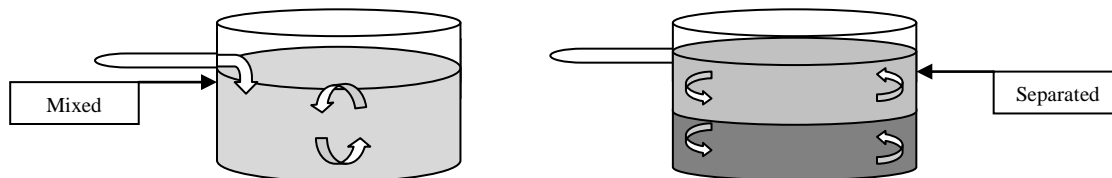
In addition to formation water, produced water from gas operations also includes condensed water. Studies indicate that the produced waters discharged from gas/condensate platforms are about 10 times more toxic than the produced waters discharged from oil platforms. The chemicals used for gas processing typically include dehydration chemicals, hydrogen sulfide-removal chemicals, and chemicals to inhibit hydrates. Well-stimulation chemicals that may be found in produced water from gas operations can include mineral acids, dense brines, and additives. Volatile hydrocarbons can occur naturally in produced water. Concentrations of these compounds are usually higher in produced water from gas condensate producing platforms than in produced water from oil-producing platforms. For more information concerning the components of produced water please reference the “White Paper,” prepared by Argonne National Laboratory, which describes produced water from the production of crude oil, natural gas, and coal bed methane.

Traditionally, the commission has been inconsistent in reviewing emissions associated with produced water. Previous guidance related to produced water emissions included:

- (1) Calculate emissions assuming 100 percent of emissions from working, breathing, and flash are from crude oil/condensate. This is an overly conservative estimation of emissions from produced water, and will ensure compliance with emissions limitations;
- (2) Use a reasonable percent or ratio of water-to-liquids production. In many instances, companies assumed 1 percent or more of all emissions from working, breathing, and flash (based on total produced water throughput) are VOCs; or
- (3) Do not quantify or register any VOCs from produced water.

Based on observations, monitoring and analysis of available information, the commission has determined that method (3) is no longer acceptable for estimating produced water emissions. Methods (1) and (2) continue to represent a very conservative estimation of emissions from produced water. Additional methods to quantify VOC and H₂S emissions have been evaluated by the commission and are listed below.

In order to account for emissions from produced water, an overview of the insoluble relationship between oil/condensate and water taking place within the tank must be addressed. Within the tank two environments exist. The first, as the produced water enters the tank it starts out as a flowing mixture. The second, as this mixture begins to settle it separates out with the oil/condensate rising to the top layer. This relationship can be visualized below. During these two environmental shifts, emissions are being produced. The emissions are accounted for as emissions from working, breathing, and flash (WBF).



All tanks receiving processed liquids (crude oil, condensate and water) will have emissions as the pressure to the tank drops. These emissions will consist of both hydrocarbons and H₂S. During this decrease in pressure upon the liquid, the lighter hydrocarbon compounds dissolved in the liquid are released or “flushed” off from the liquid. Additionally, some of the compounds that are liquids at the initial pressure and temperature of the tanks will transform from a liquid into a gas/vapor, and contribute to the vapor pressure within the tank as emissions from working and breathing. As these gases are released, some of the heavier hydrocarbon compounds in the liquid may become entrained in these gases and emitted. The magnitude of the flash gases will increase as the magnitude of the temperature and pressure drop increases, and as the amount of lighter hydrocarbons found in the liquid increases. Furthermore, the temperature of the liquid and the storage tank will influence the amount of WBF losses since the ability of a solution to dissolve or hold a gas is related to temperature. If the final temperature is lowered, the final solution can hold more gas which will result in slightly lower WBF gas emissions.

Consequently, the estimation of WBF gas losses becomes a complex process when considering all measured and theoretical properties of the fluids.

Now that more is known about what type of emissions and how they are produced inside the tank, the relationship between oil and water, and how this affects sampling of produced water, potential VOC and H₂S emissions must be addressed. According to Dalton's Law the total pressure of a mixture of ideal gases is the sum of the partial pressures of each gas component. Ideal gas behavior can be assumed for real gases at moderate pressures. For example, when obtaining a sample of produced water in order to determine flash emissions, the pressure inside the sample container should be equal to the separator pressure. Because of Dalton's Law of partial pressure, the pressure in the sample contains the sum of all hydrocarbons. The hydrocarbon component can be determined within the sample container accurately once the total vapor pressure of the sample at the sampling conditions (that is, sample temperature and pressure) is determined. Vapor pressures of water at the sampling conditions are published in most chemistry books or in thermodynamics reference books. What remains when the vapor pressure of water is subtracted is the sum of total hydrocarbon vapor pressures which are anticipated to be emitted or "flashed" to atmosphere. The sum of hydrocarbon vapor pressures divided by total vapor pressure can be used as a factor for adjusting produced water flash emissions results for VOCs from acceptable calculations methods as discussed elsewhere. However, the adjustment factor does not account for weight speciations (that is, the factor is not a weight fraction). VOCs have heavier too much heavier molecular weights than water, so, for ideal gas, the factor could be too small, and, therefore yield adjusted emissions of VOCs that may be underestimated. Furthermore, the factor also does not account for methane and ethane (not VOCs), likely yielding factor adjusted emissions results for VOCs that are overly conservative, as methane and ethane typically make a significant weight contribution to flash emissions of hydrocarbons. The commission has determined that overall, the factor adjusted VOC emissions results should be a reasonable representation of emissions from produced water tanks.

While a company may claim at least one percentage of all emissions as representative of working, breathing, and flash emissions from produced water tanks the agency would prefer applicant's representative a more accurate method in estimating these emissions. For that reason, the agency would prefer that either an actual gas and liquid analysis be used, or too conservatively estimate emissions, the tank be assumed to be 100 percent condensate or oil when estimating working and breathing losses. This is due to the fact that since the oil or condensate liquid floats on top of the water phase, it is the VOCs that are contributing to the partial pressure of the tank. Additionally, when the liquid in a water tank flashes, it can be assumed that the percentage of VOCs entrained in the water will now contribute to that same partial pressure within the tank as flash emissions. Hence, the agency believes in order to achieve a more accurate and conservative representation of emissions from produced water tanks 100 percent of working and breathing loss emissions must be assumed and combined with the percentage of VOCs entrained in the water. These results should account for the three known types of emissions associated with produced water from storage tanks.

Due to the large variation of crude and condensate properties throughout Texas and from site to site, site specific measurements are required to estimate WBF emissions from produced water. The EPA's published guidance on WBF is that the direct measurement technique provides the most accurate results, but there is no standardized published reference test method available at this time.

The commission recognizes several methods to estimate emissions, each has specific constraints. Regardless of which method is used, all supporting data used to calculate the emissions, including identification of the calculation method, description of sampling methods, and copies of lab sampling analysis, must be provided with the emissions estimate.

Tanks 4.0 is a relatively accurate program used to determine working and breathing emissions within tanks which should be run assuming 100 percent of the inputs are VOCs, then combined with a method capable of calculating flash emissions before submittal as being representative of produced water emissions.

Emission estimation methods for working, breathing and flash may use the following methods for determining emissions: Direct measurement of tank emissions requires sampling and analysis of tank contents, which can be expensive, but the results are relatively accurate; or E&P Tanks Software, V 2.0, using an option that requires site-specific sampling and information. This will require a pressurized liquid and/or gas sample analysis from the separator. In order to determine flash emissions the applicant must subtract stable oil option results from the tank with a separator option. The result should be added to 100 percent of stable oil option results in order to determine produced water emissions. The use of the Geographical Data base option is acceptable as long as the applicant can support that the information provided accurately represents the site in question.

Emission estimation methods for flash may use the following methods for determining emissions: There are several different process simulators computer programs (WinSim, Designer II, EPCON, HYSIM, HYSIS, and PROMAX, etc.). The software is accurate when based on a site-specific sample and analysis. Flash emissions must be combined with 100 percent of working and breathing emissions from Tanks 4.0 before submitted as representative of produced water emissions. Most simulators are not capable of calculating emissions from working and breathing.

1. *AQUALibrium* was developed for calculating the fluid phase equilibria in systems composed of sweet and sour natural gas (sour gas contains H₂S) and acid gases (hydrogen sulfide and carbon dioxide) in the presence of water. Flash emissions must be combined with 100 percent of working and breathing emissions from Tanks 4.0 before submitted as representative of produced water emissions.
2. Laboratory measurement of the *Gas-Oil-Ratio (GOR)* from a pressurized liquid sample is a direct laboratory analysis of the flash gas emitted from a pressurized water sample. Flash emissions must be combined with 100 percent of working and breathing emissions from Tanks 4.0 before submitted as representative of produced water emissions.
3. The *Vasquez-Beggs Equation (VBE)* is a calculation method based on empirical data. The VBE variables must be supported with a lab sampling analysis that verifies the American Petroleum Institute (API) gravity, separator gas gravity, stock tank gas molecular weight, and VOC fraction. If an operating variable used in the VBE calculations falls outside of the parameter limits, the applicant must use another method to calculate flash emissions. Flash emissions must be combined with 100 of working and breathing emissions from Tanks 4.0 before submitted as representative of produced water emissions.

The TCEQ always prefers that the most accurate emission estimates be submitted, based on site-specific, representative worst-case data when possible. Therefore it is preferred that the Vasquez-Beggs method is not used. However, if an applicant can justify any method is capable of representing an accurate estimation of emissions, it will be considered by the commission. If applicants choose to use the Vasquez-Beggs Equation, they should be aware of the risk of potentially underestimating emissions at a site. Regardless of which method is used to calculate produced water emissions, verification of the inputs and calculation methods are required. If at an existing production site, the emission calculations should be determined from site-specific or defined representative sampling or analysis.

Appropriate controls for produced water tanks are the same as those for other storage tanks, assuming there is sufficient quantity of VOC or H₂S.

3. Pressurized Tanks: Due to the fundamental nature of pressurized tanks, the only expected production operation emissions will be fugitive components and should be considered in those component counts. To ensure that pressure is maintained for tank trucks, the federal regulations from the Department of Transportation for trucks rated at 15 pounds per square inch, gauge (psig) or greater requires each tank truck shall be leak checked and certified annually (49 CFR §180.407). There should not be any emissions from pressurized tanks during operations/production. Tier I BACT is venting required during tank filling and the vented emissions shall be routed to a control device with a destruction or capture efficiency of at least 98 percent. In lieu of being equipped to vent to control, the operator may commit to maintaining an operating pressure no less than 50 psig below the set point of the relief valve.
4. Fuel Storage Tanks: Fuel storage tanks are commonly diesel, fuel oil, or less frequently, gasoline, used for fuel in combustion engines, processing equipment, mobile sources, and miscellaneous applications. The maximum size tank normally encountered for gasoline is 2,000 gallons. The maximum size tank encountered for diesel or fuel oil is larger at approximately 5,000 gallons. On an infrequent basis, some storage tanks may be converted production tanks with their capacity ranging up to and above 500 barrels. For gasoline, using a maximum vapor pressure for gasoline of 11.0 psia, tank filling rate of 2,000 gallons per hour, and the EPA Tanks 4.0 computer program, a maximum rate of 4.17 lbs/hr of gasoline emissions was calculated for the worst-case hourly tank emissions. For fuel oil or diesel fuel tanks, using a maximum vapor pressure for these materials, a tank filling rate of 10,000 gallons per hour, a vent height of 10 feet, and the EPA Tanks 4.0 computer program, a maximum rate of 0.068 lb/hr of diesel emissions is calculated for the worst case hourly tank emission. Fuel oil emissions will be much less due to the relative vapor pressure of the fuel. The maximum emissions of the two types of fuels are 0.068 lb/hr. Refineries produce high vapor pressure gasoline mainly in the fall and winter and low vapor pressure gasoline in the spring and summer. The EPA tanks program takes into account the ambient temperature when calculating emission. The combination that results in the highest emissions normally occur when the ambient temperature is relatively hot and refineries are producing a relatively high vapor pressure mainly in the fall but may occur in the spring. BACT for fuel storage tanks is the same as the BACT for crude oil and condensate tanks.

5. Treatment Chemicals Tanks: Pressurized and unpressurized tanks are used throughout OGS for storing any number of treatment chemicals used at a given site. For example, the storage of amines and glycols, which have been estimated in PBR and standard permit registrations result in <0.01 lb/hr and 0.01 tpy VOC. In one instance, a registration included several 25-bbl lubricating oil tanks with estimated emissions of 0.02 lb/hr and 0.1 tpy VOC. Tanks storing methanol for anti-icing purposes are typically fixed roof tanks generally smaller than two or three thousand gallons in size. The emissions from a small PBR authorized site having one 2,000 gallon methanol storage tank claimed 0.01 lb/hr and 0.03 tpy of VOC. A large compressor station operating under an oil and gas standard permit can have multiple tanks ranging in size from 150 to 6,660 gallons and emissions from 0.40 to 15.6 lb/hr and 0.01 to 0.13 tpy methanols. Several sites used totes which are considered to have no storage emissions when closed or sealed. A site with several tanks may need to address cumulative emissions. These are generally expected to be small, and sometimes totes are used which are delivered full to the site and taken offsite for refilling.

6. Slop/Sump Oil Tanks: The following was formulated from a variety of sources. When companies store lubricating oil for engines, they normally claim the storage tanks as engine oil or lube oil tanks. Standby lube oil pump (slop) oil is that oil which results from engine leaks and is collected in a sump or pan. Sump oil is the oil that is collected from the plant's sump (usually the lowest point on the concrete production slab) and reflective of all sources that discharge or leak hydrocarbons to the sump. Slop tanks and sumps collect hydrocarbon-laced water from a variety of sources, for example, process operations, oil/water separators, lube from engine leaks, oil-water separators, and rainwater. Historically, emissions from these sources have not been quantified because they were considered minor in comparison to the production tanks, and handle low vapor pressure heavy oils that should not result in any significant VOC or H₂S emissions. A few sites were seen to use slop oil tanks as receiving production materials when there was an "overflow" and may have up to 8 tpy of VOC. All 21 sites reviewed claimed a tank as a storage device and used no open sumps as storage container. The majority of emissions from these individual tanks fell into three categories: (1) very low (<0.1 tpy); (2) low (<1.0 tpy); or (3) 1 to 8 tpy of VOC. For the very low category, the represented vapor pressures were below the threshold for quantification as an air contaminant (<0.0002 psia). Most vapor pressures claimed were within the range of gasoline or crude oil vapor pressures. While research of file records showed a number of tanks as having very low annual tank storage emissions, the short term emissions were often as much as 20 lb/hr based on this information, these tanks should be considered for any short-term protectiveness review assessment. Tier I BACT is the same as crude oil and condensate tanks, assuming sufficient quantity of VOC emissions.

7. Truck Loading/Filling Operations: LPG products are not normally loaded or filled in tank trucks at OGS because these products are typically shipped off-site by high pressure (900 psig) pipeline operations. Loading and filling losses are the primary source of evaporative VOC emissions from crude oil, liquid condensate, produced water, fuel, and treatment chemicals during tank truck loading and filling operations. Loading losses occur from the organic vapors left in the "empty" tank truck when the vapors from the previous load are displaced to the atmosphere by the liquid loaded into the tank truck.

Additional loading losses occur by the vapors generated from the new product being loaded. If a vapor balance system is used, additional vapors are transferred to the tank in the vapor balance as product is being unloaded. Based on preliminary information found by the executive director staff only small amounts of VOC were claimed in OGS permit files during loading operations.

It is assumed that in estimating crude oil, condensate, and produced water loading emissions only one truck is loaded at a time in any one-hour period, since sites with high production rates will typically deliver directly into a pipeline. However, the Standard Exemption 66 review conducted in 1997 determined that sites with production rates above 1,000 barrels per day had annual truck loading losses of 25 tpy of VOC, which exceeds the general PBR limitations. Since that time, it has become standard industry practice to use pipelines for high production sites. In addition, the standard tank truck capacity is only 180 barrels (7,560 gallons), which makes it uneconomical to use tank trucks. For emission calculations, crude oil with a Reid vapor pressure (RVP) of 5 pounds per square inch, absolute (psia) was used in the AP-42, Compilation of Air Pollutant Emission Factors, Chapter 5.2, Tables 5.2.1 and 5.2.2, and loading emission factors emission equations assuming an empty truck was loaded to full capacity.

Based on a vapor pressure of 5.5 psia at 95.25 degrees F, the maximum surface temperature of crude oil 5 RVP (based on 1997 Standard Exemption No. 66 Protectiveness Review), in the Midland-Odessa Area according to EPA Tanks program and the AP-42 Chapter 5 Loading Loss (LL) equation, vapor molecular weight of 50, and submerged loading a tank truck in dedicated service would emit 27.8 lb/truck loaded (assuming a tank truck could handle 7,500 gallons based PBR and standard permit registrations). Splash loading can result in approximately 140 percent more emissions. Loading condensate with a vapor pressure of approximately 11 psia would double the emissions. Uncontrolled emissions included in some PBR and standard permit registrations was represented to be 40 to 60 lb/hr VOC, and in some cases with short distances to occupied off-property structures.

BACT is based on permit reviews for VOCs and requires the loading/filling operation to be submerged or bottom loaded with no splash loading. In addition, when loading VOC with a vapor pressure of 0.5 psia or greater at a maximum loading temperature, the displaced vapors must be captured and directed to control. To ensure effective capture of the displaced vapors at chemical plants and refineries the tank trucks are required to pass vapor tightness testing in accordance with the methods described in 40 CFR 60, Subpart XX, Standards of Performance for Bulk Gasoline Terminals, or 40 CFR 63, Subpart R, National Emissions Standards for Gasoline Distribution Facilities, within the past 12 months. While this BACT analysis is based on recent permit reviews, the executive director staff noted that most truck loading existing at OGS under PBR or standard permit had not been closely evaluated. After receiving comments during stakeholders meetings, the executive director staff contacted various petroleum transportation vendors to establish the availability of trucks which would meet the submerged loading requirements of Tier I BACT, and found that some operators rely on vacuum tank trucks. For these companies unable to switch from vacuum or splash loading, additional controls would be necessary to achieve emissions equivalent to submerged truck loading for dedicated liquid normal service. It is also unclear how effectively all tank trucks used at OGS across the State could be tested for vapor tightness to insure sufficient capture.

Loading loss capture efficiency where vapor tightness cannot be assured is estimated to be only 70 percent effective. (See AP-42, Transportation and Marketing of Petroleum Liquids, Chapter 5.2, 6/08 edition)

OGS truck loading BACT is required with bottom or submerged fill or controlled equivalent for material with a VOC partial pressure of 0.5 psia or greater at the maximum loading temperature or 95°F whichever is greater. Then, where site loading has an uncontrolled potential to emit (PTE) equal to or greater than 5 tpy VOC, the displaced vapors must be captured and controlled with device meeting BACT. The control device preferred is a vapor recovery unit that can achieve 95 percent VOC recovery or destruction control meeting at least 98 percent is required. This control can be connected directly to the tank truck being loaded or the tank truck vapors can be piped back in a vapor balance to the storage tank being unloaded, if the storage tank is connected to the control device. The vapor tightness testing is not being mandated at this time for BACT, so capture must be estimated at 70 percent efficiency; but the executive director's staff will study the potential for mandating the testing at adoption and requests comments on the feasibility of compliance across the State. Loading should not be conducted where lines and equipment are obviously in disrepair and leaking. OGS needing additional capture to meet impact requirements will need to retain records on the tank trucks loaded to show they passed leak tightness testing within 12 months prior to being loaded. The capture efficiency should be assumed to be 99.2 percent for tanker trucks passing the MACT-level annual leak test (not more than 1 inch water column pressure change in 5 minutes after pressurizing to 18 inches water followed by pulling a vacuum of 6 inches water). A collection efficiency of 98.7 percent (a 1.3 percent leakage rate) should be assumed for trucks passing the NSPS level annual test (3 inches pressure change).

The commission continues to evaluate possible operations and requirements for BACT expectations for crude oil and condensate loading. Emission from loading trucks can be a substantial portion of VOCs from an OGS. The commission therefore expects these emissions to be included in the assessment of the total uncontrolled VOC emissions so that if substantial, these emissions could be routed to a recovery (VRU) or control device (flare) as described above.

8. Underground Storage Caverns: As a result of stakeholder comments, the commission reviewed several OGS which have underground storage of gas and liquids. A variety of products are currently stored in different types of underground formations across the country. The products stored may be referred to as natural gas, natural gas liquids, highly volatile liquids, or simply hydrocarbon product. The specific compounds stored vary from site to site. There are various reasons for underground storage of hydrocarbons. Long term storage of natural gas is necessary to build up enough supply for the winter (or other time when demand increases). Short term storage is necessary for selling to occur during favorable market conditions. An extra supply is also needed for emergency situations.

Hydrocarbon product storage can occur in salt caverns, depleted gas reservoirs, or aquifers. Statistics from the U.S. Energy Information Administration show that at the end of 2007 in Texas there were 14 salt cavern storage sites, 20 depleted reservoir storage sites, and zero aquifer storage sites. A search of permits issued by the commission resulted in several salt cavern storage sites, but did not result in any depleted reservoir storage sites. The reason for this discrepancy is uncertain; further research on depleted reservoir storage is required.

In general, salt caverns are utilized for short term storage and reservoirs for long term storage due to the fact that product can be withdrawn at a faster rate from salt caverns. Another difference is that the storage capacity of salt caverns tends to be smaller than the storage capacity of reservoirs. In salt dome formation storage, brine (salt water) is used for displacement of the product being stored. The brine also maintains pressure in the formation. When brine is pumped into the bottom of the cavern filled with product, since it is heavier (more dense), it displaces the product out of the cavern. As product enters the storage cavern, an equal volume of brine is displaced and pumped out. The brine is usually stored in an open pond or pit; however, it can also be stored in a tank. Since the brine and product do come into contact with each other, mass transfer does occur to some extent. Some amount of water gets dissolved into the product and some amount of product gets dissolved into the brine. This means that dehydration may be necessary to remove water from the product after it exits the storage cavern. This also means that there will be a certain amount of flash vapors released when the brine is removed from the storage cavern and exposed to ambient conditions. If the entire dissolved product does not flash out of the brine, there will also be evaporative losses (working and breathing losses) from the brine storage area.

The extent of mass transfer between the brine and the product depends on multiple factors. The chemical composition of the product has an effect because of the difference in solubility of each chemical into water and of water into it. The vapor liquid equilibrium is affected by pressure and temperature. The frequency of moving product in and out can also have an effect. Whether or not dehydration of the product is necessary would depend on the water content specification of the customer.

The emission points, equipment, and activities expected to be seen at salt cavern underground hydrocarbon storage sites are:

- Compressors (to move the gas);
- Pumps (to move the liquids);
- Brine ponds, pits, or tanks (to store the brine when it is not underground);
- Brine degassing drum or other similar unit (to separate out hydrocarbons dissolved in the brine; the separated vapors can be flared or recovered);
- Flare, other type of destruction device, or recovery system (to destroy or recover separated vapors to prevent venting to the atmosphere or for upset events);
- Dehydrators (to remove water from the product);
- Piping systems (to direct process streams including incoming and outgoing flow of product and brine to and from storage);
- Fugitives; and
- MSS (well work over or cavern degassing events are done in accordance with Texas Railroad Commission maintenance requirements; the product can be stored, sent to pipeline, or flared as a worst case; high hourly emissions are expected to result).

Most of the emissions associated with normal operating conditions at salt cavern underground storage sites are expected to be similar in nature and amount to typical oil and gas production site operations, especially if brine hydrocarbon flash vapor and MSS emissions are well controlled.

Under emergency conditions emissions could potentially be much greater and could result in problems. Possible problems associated with underground storage are overfilling, leaks, migration, abandonment, well-head failure, failure of the emergency shutdown valve; fires and explosions are possible outcomes. Because of the amounts and pressures of storage materials, underground caverns are currently the safest and most economical way to meet the storage needs that exist.

A permit from the Texas Railroad Commission is required for any creation, operation, or maintenance of an underground hydrocarbon liquid or gas storage facility. The Texas Railroad Commission Rules are in Title 16 of the Texas Administrative Code, Part 1, Chapter 3. The rules are:

- §3.95 Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations
- §3.96 Underground Storage of Gas in Productive or Depleted Reservoirs
- §3.97 Underground Storage of Gas in Salt Formations

All of these rules have provisions for preventing uncontrolled releases, pollution of fresh water, and danger to life and property. Safety measures are required including an emergency response plan. The permit must be amended if there are changes to the storage zone such as an enlargement of the storage zone or increase in volume stored from what was permitted. Public notice, monitoring, recordkeeping, testing, maintenance are required.

A database search of air permits issued by the commission containing underground storage was performed. Out of eight air permit projects looked at from the search, all were for storage in salt formations. Two projects were looked at in detail and chosen due to the amount of details available in the original permit application.

The first project is for a petroleum products storage facility and pipeline pumping station. The products stored are natural gas liquids (NGL). The storage capacity of the underground salt dome formations is greater than 300,000 barrels (bbl). Brine is stored in three large surface pits. The pump rate for each pit is 9,625 bbl brine/hr and the annual throughput for each pit is 14,000,000 bbl brine/yr.

The emission points associated with this project are: fugitive emissions; two Emergency Management Units; three brine pits; one emergency electrical generator; one fire water pump; two fuel tanks; one maintenance flare; and MSS degassing. The emergency management units (which replaced less-efficient burn tanks) are safety devices that burn vapors by exposing the brine to a pilot flame before it enters the brine pit. The emissions represented for each of the three brine pits are 4.85 lb/hr and 2.92 tpy of VOC. An emission factor was developed based on testing (2003) which established a mass of VOC generated for every barrel of brine displaced by product. The testing was done in accordance with EPA method 25D from 40 CFR Part 60, with a few modifications made. Brine pit emissions were estimated by multiplying the volume percent of each component in the product stream by either the hourly pump rate or annual throughput of brine and then by the emission factor for that component.

The second project is for an underground hydrocarbon storage facility consisting of 19 caverns in a salt dome. A variety of petroleum hydrocarbon products and gases are stored including but not limited to n-butane, i-butane, i-pentane, hydrogen, natural gas, propane, ethane-propane mix, butanes-butylenes mix, NGL, propylene, and ethane. There are two separate brine systems, a sweet one and a sour one. The hourly sour brine throughput is 3,400 bbl/hr and the annual sour brine throughput is 5,246,654 bbl/yr. The hourly sweet brine throughput is 4,700 bbl/hr and the annual sweet brine throughput is 22,532,692 bbl/yr.

The emission points associated with this project are:

- Four compressor engines
- One diesel engine
- Two fire pump engines
- Five process heaters
- Four flares
 - One sour brine degassing flare (4.23 tpy VOC, 0.01 tpy H₂S, 0.01 SO₂)
 - One sweet brine degassing flare (3.11 tpy VOC)
 - One main process flare (12.31 tpy VOC)
 - One brine degassing pit flare (0.19 tpy VOC)
- Various miscellaneous tanks
- Four brine ponds
 - Two sour (0.10 tpy VOC each, no H₂S represented)
 - Two sweet (20.09 tpy VOC each)
- Storage pond/brine degassing pit (4.89 tpy VOC)
- Brine Pond Vents
 - Two sour (0.05 tpy VOC each)
 - Two sweet (4.18 tpy VOC each)
- Painting and abrasive blasting
- Fugitives

A knockout drum and flare remove product from the brine before it enters the reservoir (separate knockout drums and flares are used for sweet brine and sour brine). The brine pond vent is the pipe that the brine dumps out of to go into the brine ponds. When brine water needs to be disposed of it is pumped to a brine degassing pit. The brine degassing pit flare is used to ignite any gases entrained in the brine prior to the occasional disposal of the brine.

Emissions from the brine ponds and brine pond vents (amounts shown above) were estimated using a mass balance approach. The flow to the brine degassing flares is also estimated with the mass balance approach. The known stream concentrations and flow rates appear to be from actual measured data; however, no testing results are presented in the application.

In order for an air authorization to be issued, emission estimates are required for all potential sources of emissions. More research needs to be done to determine the best methods for estimating the hydrocarbon emissions from brine and from MSS activities. Since there are not currently many underground storage sites permitted by the commission, there is no established emission estimation approach. There is also uncertainty in the amount of underground storage sites that would qualify for permit by rule or standard permit authorizations as opposed to case-by-case permits.

If a site does meet the applicable emission limits and other requirements, the site should be able to be authorized by the permit by rule or standard permit as applicable provided that valid emission estimates are provided.

Possible emission estimation methods for the amount of hydrocarbon vapors released from the brine could include both the sampling and the mass balance approaches discussed above. For sampling of the brine, a pressurized sample needs to be taken before it reaches open atmosphere and analyzed so that the amount of flash emissions can be properly quantified.

The reason the commission is authorizing underground storage of gas or liquid hydrocarbons and the associated surface support facilities under the oil and gas PBR and standard permit is because under normal operating conditions emissions are expected to be similar in nature and amount to typical oil and gas production site operations. Under emergency conditions, the emissions could potentially be great and result in a disaster; however, the commission does not have jurisdiction to regulate upset conditions. Instead, the Texas Railroad Commission is the regulatory agency in charge of safety and disaster planning. The commission, therefore, authorizes emissions from underground storage of gas or liquid hydrocarbons and the associated surface support facilities under the Oil and Gas Permit by Rule and Standard Permit only if the storage operation is permitted by the Texas Railroad Commission and in compliance with all applicable Texas Railroad Commission rules.

J. Vapor Recovery Systems

Two common control systems used at OGS are vapor recovery systems (VRS) and thermal destruction units. VRSs can cover different types of recovery systems, both by mechanical and chemical means. VRSs are designed to capture vapors from process vessels such as oil/condensate tanks and produced water tanks. VRSs can cover different types of recovery systems, both by mechanical and chemical means. The most common type seen at OGS are the mechanical type, which use a compressor to collect the vapors and route them to a condenser, where the liquids are sent back to the tank and the gases to the sales pipeline. The other type is a liquid system, where the vapors are routed through a liquid and they are absorbed into the liquid. These systems are also vapor recovery systems because the vapor that has been absorbed can be recovered for profit. The VRSs that use mechanical means will be referred to as mVRUs and those that use chemical means will be referred to as lVRUs.

In a typical design for mVRUs, one or more tanks are manifolded to a common suction line and piped to the suction scrubber on the mVRU. An independent sensing line is run from the most active or farthest tank to the sensing unit on the mVRU. The discharge piping from the mVRU is connected to the gas gathering line, a meter run, or the suction of the field gas compressor. Condensates that fall out in the suction scrubber are generally piped back to a stock tank. Typically, mVRUs are configured to stop and start automatically, depending on the pressure in the tanks. An efficiently designed mVRU must incorporate a bypass system that will initiate automatically and divert the discharge volume back to the suction scrubber. This process allows tank pressure to build back to the point at which collection occurs. If the pressure continues to decrease while in the bypass mode, the unit will shut down and wait in standby for the start pressure to be obtained. Additionally, mVRUs should be configured to shut down before any type of vacuum is reached to avoid pulling oxygen into the tanks or imploding them.

If oxygen does get pulled into the system, it is typically caused by an improperly designed package, improperly sealed tank hatches, or leaking relief valves. Therefore, the use of a gas blanketing system on the tanks could assist in alleviating the majority of these issues and other potential issues that could cause oxygen ingress.

Compressor selection plays a critical role in the overall efficiency of the mVRU. The ability to effectively handle wet gas (condensate/water) is essential in this application. The wet gas in this application tends to foul the valves and seals in reciprocating compressors, and condensate falls out in the crankcase and compromises the lubricating oil, resulting in component failure. Reciprocating compressors are most effective in dry gas (absent of condensate) applications, but ultimately are found to be unreliable for mVRU service.

One recent change that has made a significant difference in mVRU accuracy is with pressure sensors. Due to the extremely low operating pressures encountered when capturing vapors, the early pressure-sensing devices were large and somewhat cumbersome pilot valves. These pilots were essentially mechanical devices that utilized moving parts, which were subject to corrosion and fatigue. Electronic transmitters have replaced pilots and operate much more reliably at extremely low pressures. With essentially no moving parts, they are better suited for the application and require dramatically less maintenance. The accuracy of these devices is far better than pilot valves, and enables more finite control of the mVRU to adapt to tank pressures fluctuations. Variable speed drives on electric-driven compressors have been another important advancement in mVRU technology. These new drives enable more turndown capability to respond to the daily variations in pressures associated with the process vessel being controlled. The ability to control the speed of a compressor as a result of the changing tank conditions allows for a more flexible unit. Variations in pressures and volumes can occur multiple times within a tank resulting from seasonal temperature changes or changes in production. Therefore, having the capability to vary the operating speed of the compressor to respond to these changes is essential in capturing vapors under all operating conditions.

In order to use the liquid system and claim 95 percent – 98 percent control efficiency the system must meet the manufacturer's design and pounds of VOC to pounds of liquid reactant specification. The replacement of the liquid must follow manufacture's recommended procedure. This involves a separate temporary system to capture the vapors during the refill. 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. 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 $1 - (\text{inlet} - \text{outlet}) / \text{inlet}$. This testing needs to be performed and results recorded to receive 95 percent control efficiency no longer than: vacuum truck emissions: after 20 loads have been pulled through the IVRU, for tanks: Produced Water – Monthly, Crude – Bi-Monthly, Condensate – Weekly. This testing needs to be performed and results recorded to receive 98 percent control efficiency no longer than: vacuum truck emissions: after 15 loads have been pulled through the IVRU, for tanks: Produced Water – 3 weeks, Crude – 10 days, Condensate – 5 days. One of the advantages of this type of system is that there are no emissions from a combustion device, it can take low levels of VOC in the vapor phase, and there is no expected "downtime" since a temporary system handles the VOCs during refilling.

In summary, mVRUs are designed to capture vapors from process vessels such as oil/condensate tanks and produced water tanks. For this reason, the TCEQ has decided that in order for a control device to be recognized as a basic mVRU, it must capture vapor and include a sensing device set to capture this vapor at peak intervals. The efficiency of the mVRU to capture this vapor will increase as additional design parameters are utilized such as: additional sensing equipment, a properly designed bypass system, an appropriate gas blanket, an adequate compressor selection, and variable speed drives for electric driven compressor units.

These additional design parameters should satisfy the following requirements in order for the TCEQ to accept their efficiency rating. The sensing equipment should be sufficient to monitor vapor pressures within the controlled process vessels. The bypass system should initiate automatically and divert the discharge volume back to the suction scrubber allowing tank pressure to build back to the point at which compression occurs. Additionally the system should be configured to shut down before any type of vacuum is reached to avoid pulling oxygen into the tanks, or imploding them. The use of a gas blanketing system on the tanks should be used to assist in alleviating the majority of any other issues that could cause oxygen ingress. Compressor selection should be made to sufficiently recover both wet and dry gas with minimal adverse impact on the compressor unit. Variable speed drives on electric-driven compressors are essential to respond to the daily variations in pressures associated with the process vessel being controlled.

For these reasons the TCEQ is willing to accept that an applicant may claim up to 100 percent control efficiency for mVRUs provided both the basic design function and additional design parameters of a mVRU are satisfied. Records identifying these additional design parameters are utilized will need to be provided. Additionally, records demonstrating that all tank hatches and relief valves are sealed properly (according to design) must be maintained for this control efficiency to be recognized. For applicants wishing to opt-out of the record keeping requirement control efficiency up to 99 percent will be acceptable. For units which do not incorporate additional design parameters and/or maintain records of the mVRU the TCEQ cannot reasonably support control efficiencies greater than 95 percent.

The TCEQ recognizes that there will be periods of mVRU compressor maintenance and hence the capturing of vapors from the process vessels under control will cease. The agency has determined that this period of mVRU compressor maintenance could potentially be for up to five percent of the year. As a result, the agency has determined that while an mVRU may potentially attain a control efficiency of 100 percent this efficiency may only encompass approximately 95 percent of the year. These emissions are not considered Maintenance, Start-up, and Shutdown (MSS) emissions because the emissions from the process vessels have not ceased, only the control of these emissions have ceased. For this reason the emissions released from process vessels no longer under control are considered intermittent emissions representing an alternative operating scenario. Therefore, applicants must represent that these emissions are from an alternative operating scenario. Additionally, seals associated with mVRU compressors must be accounted for and represented with fugitive emissions.

These IVRU systems has been evaluated by the commission, and its effectiveness proven if the liquid is tested and changed before the effectiveness reaches less than 95 percent. These systems can capture emissions from all VOCs tested, which include the most common at OGS. The system must meet the design parameters given to the manufacturer for capability to handle the stream going to the IVRU.

If the system is tested as noted and the liquid changed before the efficiency gets below either 95 percent or 98 percent (as claimed and demonstrated) as a result of sampling and testing, then these systems can be used at OGS. It is important to note that the schedule below is the maximum time allowed between sampling, depending on the claimed control efficiency. If the system has reached the maximum time limit, and the system has been tested, and testing shows that the system is still capturing at a greater efficiency than claimed, the liquid does not need to be changed immediately. If claiming 95 percent, the system can be tested two days later. If claiming 98 percent, the system can be tested one day later. The current effectiveness can be extrapolated to determine the day the liquid will reach its minimum effectiveness (95 or 98 percent) and the liquid will need to be changed on that day. A record of the sampling, extrapolation, and liquid replenishment must be kept to demonstrate the effectiveness to the Regional office or Local program. Due to the type of capturing system, there will need to be adequate sampling, monitoring and recordkeeping regardless of efficiency. The choice of efficiency is up to the owner/operator on how effective they want their system to work and frequency of liquid changes.

The typical design for an IVRU has the tank or loading rack set up so the vapors flow through a submerged reaction chamber, this interaction between the waste gas and the liquid within the reaction chamber creates an environment where the VOCs are absorbed/adsorbed. The design of the system should be consistent with the expected flow of the VOC source. Physical absorption depends on properties of the exhaust stream and the liquid such as density and viscosity, as well as specific characteristics of the hydrocarbons in the exhaust stream. These properties are temperature dependent. Lower temperatures generally favor absorption of hydrocarbons by solvent. Absorption is also enhanced by higher liquid-gas ratios and higher concentrations in the hydrocarbon stream. Chemical absorption may be limited by the rate of reaction, although the rate-limiting step is typically the physical absorption rate, not the chemical reaction rate. The more the vapor stream goes through the liquid, the less effective it becomes overtime, therefore, it needs to be sampled, tested, and replaced in a timely manner to make sure that it is reaching the desired effectiveness. The vapor is recovered because the saturated liquid can then be put into the crude or condensate tank. The saturated liquid is high in BTU, and adds to the value of the produced liquid. The vapor is recovered when the crude or condensate is refined.

K. Flares

Flare systems generally are open-flame control devices used for disposing of waste gas streams during routine process operations, planned maintenance operations such as engine/compressor blowdowns, and emergency or upset conditions. In addition to simple, unassisted flares, typical smokeless flare systems include, but are not limited to, the following:

1. Enclosed Flares: Enclosed flares are used in disposing of waste gas streams in instances where a visible flame is unacceptable. Applications of this type of flare include chemical processing, petroleum refining and production, and municipal waste gas treatment.
2. Steam-Assisted Flares: Steam-assisted flares are used in disposing of low-pressure waste gas streams when steam is available and practical to use to minimize smoking from the flare. Applications are similar to those of enclosed flares, and they can also be assisted with natural gas, if available on site.

3. Air-Assisted Flares: Air-assisted flares are used in disposing of low-pressure waste gas streams when practical or when steam utilities are not available to minimize smoking from the flare. Applications include chemical processing, petroleum refining and production, and pipeline transportation.

In the review of PBR, standard permits, and permitted OGS, the typical flare type found was an unassisted flare. Typical pollutants listed were products of combustion (NO_x , CO, VOC, SO_2 and PM) in addition to undestroyed VOC and H_2S and SO_2 from the oxidation of H_2S . Process flares designed to meet 40 CFR §60.18 requirements are assumed to achieve 98 percent control of VOC and H_2S and 99 percent for VOCs containing no more than three carbon atoms that contain no elements other than carbon and hydrogen. This should include specifications of smokeless operation; minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring. If necessary to ensure adequate combustion, sufficient fuel gas shall be added to make the waste gases combustible.

Flares are expected to handle a potentially rapidly varying waste stream, from no flow to maximum rate and heating value in short periods of time, so some incidental incomplete combustion can occur, and up to 5 minutes of smoking in any 2 hour period has been accepted in both 40 CFR §60.18, state regulations and NSR permits. Acid gas flares as defined in 30 TAC §101.1, Definitions, associated with sweetening processes have a unique potential for visible emissions even when efficiently combusting the waste gas. High sulfur content can be combusted to sulfur trioxide (SO_3) which when exposed to water from combustion and a humid atmosphere can form a sulfuric acid (H_2SO_4) mist that can be visible as a white plume. Exception from the visible emission limitation is allowed for acid gas flares covered under 30 TAC §111(a)(4), which directs acid gas flares to meet the general opacity limitations of 30 TAC §111(a)(1). Note, black smoke from an acid gas flare lasting more than 5 minutes would indicate improper operation of the flare. Flares in particular continue to be reviewed for effectiveness, especially in situations when large masses of waste gases are sent to these units in short periods of time. These and similar issues on effectiveness will continue to be evaluated in separate actions by the commission.

An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes. An automatic ignition system may be used in lieu of a continuous pilot at sites that are not subject to NSPS. For OGS sites subject to NSPS Part 60, flares must meet the requirements of 40 CFR §60.18 and exceptions for auto ignition would have to be approved in advance in accordance with the applicable rules.

Flares designed to 40 CFR §60.18 criteria should be capable of converting at least 98 percent or more of the H_2S to SO_2 . By assuming that 100 percent of the H_2S is converted to SO_2 for air permitting emissions estimates, this ensures that the maximum amount of SO_2 is evaluated as emitted from the flare.

Tier I BACT for flares includes a requirement that all flares are designed in accordance with the specifications for smokeless operation, minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring found in 40 CFR § 60.18. Fuel for all combustion units and flare pilots shall be sweet natural gas or liquid petroleum gas, fuel gas containing no more than five grains of total sulfur per 100 dry standard cubic feet (dscf), or field gas.

If field gas contains more than 1.5 grains (24 ppmv) of H₂S or 30 grains total sulfur compounds per 100 dscf, the operator maintains records, including at least quarterly measurements of fuel H₂S and total sulfur content, which demonstrate that the SO₂ emissions from the site do not exceed regulatory standards.

More than 50 permit files and 20 flare specifications were reviewed. In these files, flare stream energy content ranged from 1,000 to 2,500 Btu/scf from a high BTU source, however since other source streams exist throughout the state, a conservative value of 200 BTU/scf was used. The flare heights reviewed varied from 20 feet to 200 feet in height, but typically the flare height was 40 feet or less. Flare tip diameters ranged from one inch to 7.75 feet in diameter with a typical diameter less than one foot. The burner tip velocities varied from over 70 feet per second to less than 0.10 foot per second. Since such wide ranges were found in the data available, flare parameters such as diameter, velocity, energy content, and temperature were discussed with the Research Manager for John Zinc Company (a flare vendor in Texas) in order to verify typical flare parameters for units used at OGS in Texas. Since the dispersion characteristics of flares and thermal destruction devices are substantially different than process units, it was determined that a separate impacts analysis needs to be performed.

Products of combustion included emissions from both burning a continuous pilot and flared destruction of waste gas streams from an OGS and included the following: 0.05 to 4.5 tpy NO_x, 0.10 to 60 tpy CO, and approximately 0.01 tpy PM₁₀. Since sulfur compound releases vary based on sour gas handling processing, the highest reasonable values were noted for review, ranging from < 0.01 to 125 lb SO₂/hr. The hourly emissions of VOC also ranged substantially depending on the type and amount of waste streams sent to the flares, within a range of 0.01 to 7.5 lb/hr. A limited percentage of OGS represent routing blowdowns to flares. Input from stakeholders is needed to further evaluate MSS activities which are vented to flares, and what emissions releases would result when an OGS's flare is not operating, especially if a site continues other processing operations.

As discussed above, it is expected that flared gas streams meet minimum heating value and maximum tip velocity requirements. It is important that these requirements are met to ensure that good combustion/waste gas destruction occurs. Flares achieve good combustion/waste gas destruction by direct flame contact of a gas stream burner flame zone. The minimum heating value requirement is needed because the heating value of the waste gas (plus assist if needed) must be high enough for good combustion to occur. The maximum tip velocity requirement is needed because achieving good combustion is dependent upon the waste gas having sufficient flame contact time in the burner flame zone, meaning that the waste gas must have a slow enough velocity to allow for that contact time.

The standard permit requires that flares be designed and operated in such a way that ignition of the flare tip and proper combustion of the stream is achieved. Proper design and maintenance of the flare will insure that the stream going to the flare will be combusted and the emissions controlled. These requirements insure that the flare being used to control emission limits will meet the emission limits of the standard permit, including: flare tip, velocity, heating value, and opacity requirements of §106.492, Flares, and 40 CFR §60.18.

Requiring sufficient heat content of the waste gas plus assist gas stream, continuously burning pilot or auto-ignition system, and smokeless operation ensures that the flare operates at the optimum 98 percent VOC destruction and 100 percent H₂S conversion to SO₂. To achieve this performance, flares require the appropriate amount of waste and fuel flow for complete combustion to occur in the flame zone, but not so much that the stream passes through the zone uncombusted. These requirements should be used by any flare at an OGS. This is important when typical operations are considered and effective control of emissions is needed. For example, when wells are flooded with CO₂ and resulting emissions vented to an emergency/upset flare, many units that are not designed or operated correctly will not ignite, and no control is achieved. This paragraph also requires all flares to be lit when receiving any waste gas stream (production, planned MSS or emergency/upset). Although this may seem inherently understood as a basic operational necessity, this requirement is not specifically addressed in 40 CFR §60.18 or §106.492. Having the flare lit is essential to the proper performance of the device in controlling emissions.

Monitoring of heat content and flow rate is not required; however, it is encouraged because it would ensure at all times that flared streams have sufficient heating value and do not have excessive flow. It is expected that the OGS owner or operator is aware what streams are or could possibly be routed to the flare and what the stream heating value and flow rates are and if needed assist gas must be used.

L. Other Control Systems and Facilities

Thermal oxidizers are not represented at OGS nearly as much as flares. These control devices can be designed to meet very high VOC control efficiencies, by meeting minimum operating temperature (as measured either in, or immediately downstream of the enclosed combustion region), residence time. Typically 95 percent to 99.9 percent destruction efficiency can be achieved and demonstrated depending on the design and the level of monitoring or testing applied. Thermal oxidizers achieve good combustion/waste gas destruction by routing the gas stream through a high temperature enclosed combustion chamber heated by the separate firing of fuel gas through one or more burners for a sufficient amount of time. Good combustion can be assumed to occur if the combustion chamber temperature is maintained at 1400 degrees F or greater and the waste gas spends at least 0.5 seconds in the chamber. The minimum operating temperature required is 1400 degrees F because that is the generally accepted temperature, based on historical testing, and is necessary for destruction of typical oil and gas production industry waste gas. A different temperature or residence time can be used if justified by testing.

This design has become commonly available and is commonly equipped with continuous temperature monitors. This is an extremely effective destruction device, but only if operated properly and maintained in good working order.

Vapor combustors are a category of thermal controls that operate in a similar manner to flares and oxidizers, but do not meet the exact design and operational specifications of either device. Due to the variability in these units, a range of parameters are considered to ensure effective VOC destruction. In general, vapor combustor flame tips should be designed to the same criteria as flares, ensuring sufficient heat content of the waste gas plus assist gas stream for good combustion. The velocity of waste and fuel must be enough to completely combust the waste stream in the flame zone, but not too much that the VOC stream does not remain in the combustion zone.

Vapor combustors achieve good combustion/waste gas destruction first by direct flame contact of the gas stream, which has a high enough heating value, in the burner flame zone for a long enough period of time, then additional residence time and sufficiently high temperature is provided in the enclosed combustion region, which is the region between the burner flame zone and the exit point. Vapor combustors need a maximum burner tip velocity requirement because achieving good combustion is in large part dependent upon the waste gas having sufficient flame contact time in the burner flame zone, meaning that the waste gas must have a slow enough velocity to allow for that contact time.

A continuously burning pilot flame during all times waste gas is present (or auto ignition system) is necessary for a properly operating vapor combustor. The operation of these units should result in no visible emissions (smokeless). Similar to oxidizers, vapor combustors also rely on a minimum temperature to properly operate, as measured either in, or immediately downstream of the enclosed combustion region. The expected temperature of these units is 1400 degrees F, but the executive director does allow operators to establish other temperatures at which the units can operate. Operators may provide manufacturer specifications and test data showing certain parameters and operations are effective in controlling VOCs (if the units will be operated at the same conditions and using the same material). Another alternative is individual unit testing. This approach is used if the units will be operated at different conditions or service from the manufacturer testing. For test results to be accepted for a certain unit, testing must be specific to the same control unit manufacturer, model, size, and the type of vapor stream being controlled. Communication with the appropriate regional office for a pre-test meeting to determine all the appropriate testing criteria is recommended. It is also recommended that the regional office be given the opportunity to observe the actual testing. Testing should be done for worst case scenarios using the most difficult material to combust and highest flow rate. If the site is subject to 30 TAC §§115.541-549, testing must be done in accordance with the approved test methods of 30 TAC, §115.545.

Thermal oxidation and vapor combustion control devices may claim design destruction efficiency from 90 to 99.9 percent for VOCs and H₂S depending on the design and the level of monitoring and testing applied as described in the standard permit.

M. Planned Maintenance, Startup and Shutdown

Recent changes to 30 TAC Chapter 101, General Rules, for the first time provide a clear expectation and mechanisms to authorize planned MSS, with a specific schedule depending on Standard Industrial Classification (SIC) code. Although the oil and gas industry's scheduled date is not until January 5, 2012, the standard permit includes an assessment and evaluation of anticipated MSS activities. It is only under these requirements and limits that MSS is authorized since no previous version of the PBR or standard permit clearly reviewed these emissions. All existing OGS which have claimed historical versions of the OGS PBR or standard permit should use these limits for any MSS releases after the standard permit has been adopted and issued by the commission. It should also be noted that MSS is not required to be authorized and sites will not lose their existing affirmative defense opportunities until January 5, 2012.

All emissions including planned MSS are emitted from the OGS through the equipment or process emission points as fugitive components, loading/filling vents, tank vents, process vents, blowdowns or flares, except for the maintenance emissions described in the following paragraph. These emissions are usually the same in character as production emissions.

These emissions, however, are not usually the same in quantity as production emissions, especially on a short-term hourly basis. Emissions associated with MSS at OGS are similar in nature to the same sources found at refineries. The executive director staff's is currently addressing calculation methodologies and BACT with individual applicants and industry groups for the required deadline of planned MSS reviews at refineries. It is the executive director's expectation that BACT requirements and emission estimation methods for OGS sources will match those established for refineries for similar sources.

1. Temporary Maintenance Facilities: For most industrial sites, maintenance on existing equipment must be performed by temporary equipment brought on-site for short periods of time. In addition, these operations do not typically occur simultaneously with normal production operations or have similar emissions. The evaluation also focused on limitations that are equivalent to de minimis facilities and activities, which by definition do not constitute or contribute to a condition of air pollution.

Temporary or permanent maintenance facilities include abrasive blasting, surface preparation, and surface coating operations on immovable, fixed structures. Historically, the commission has authorized these maintenance activities under 30 TAC §106.263, (Routine Maintenance, Startup, and Shutdown of Facilities and Temporary Maintenance Facilities) if the blasting, surface preparation, and coating supplies and equipment are taken to the object fixed in place and there is no practical means of moving the object to a designated area for surface preparation. If an object can be taken to a designated area, then other PBRs such as §106.433, (Surface Coat Facility), and §106.452, (Dry Abrasive Cleaning), would apply. Other portions of this proposal cover engines and turbines during testing and repair. Since 1995, the commission has allowed testing of an engine or turbine to be considered as part of the maintenance on that unit and authorized emissions associated with testing under §106.263 when it occurs at a maintenance shop or business. Also included are engines, compressors, pumps, and associated purging which are associated with maintenance activities. These additional units are frequently seen in the field when maintenance activities occur and have historically been authorized under §106.263. The use of §106.263 is not intended for replacement units, but only additional temporary facilities which are needed during maintenance. Finally, temporary piping and associated facilities are needed to bypass a unit or section of pipeline during maintenance situations is covered because as such bypass lines reduce or eliminate emissions during maintenance. Long-term emissions for these temporary facilities are limited to a cumulative, site-wide, rolling 12-month basis to prevent significant accumulation of emissions authorized by these conditions. For all of these types of facilities and operations associated with planned MSS, the executive director expects OGS to use those specific PBRs which cover the referenced activities and combine those emissions with other, permanent facilities to demonstrate compliance with applicable general limits of 30 TAC §106.4, Requirements for Permitting by Rule, or §116.611, Registrations to Use a Standard Permit.

2. Compressor Blowdowns: Compressor blowdowns allow emissions to be released through a stack or opening when an OGS temporarily vents a gas compressor. To establish typical parameters and expected emissions from this activity, numerous PBR, standard permit, and permit files were reviewed. Three sites with the highest MSS blow down emissions were reviewed in order to select modeling parameters.

The sources had release heights of 20 feet, exit diameters ranged from 0.5 to 6 inches, average exit velocities claimed varied from 1.4 to 140 ft/sec, and the exit temperature was assumed to be equal to the ambient temperature. Emissions from blowdowns range widely depending on the amount of piping and the pressure and how much vapor or liquids remain in pipes and equipment prior to shutdown of compression at an OGS. The frequency of blowdowns also depends on the operational conditions of any given site. Typical representations for PBR and standard permit registrations range from 20 lb VOC/hr to over 200 lb VOC/hr uncontrolled for “blowdowns” and annual emissions ranged from 0.1 tpy to 15 tpy. Based on a Tier II evaluation of BACT for compressor blowdowns, if the total uncontrolled VOC emissions from compressor blowdowns and other high potential uncontrolled sources at the site equals 10 tpy or greater, then these emissions should be routed to a control or recovery device with a destruction or capture efficiency of at least 95 percent (flares or VRSs). Operators can also reroute blowdown vent streams to blowdown casings and then ramp the pressure up, routing the stream back into the system. In many cases, blowdowns can only be recovered to a low pressure system only, but new techniques can allow this recovery to occur in high pressure systems.

3. Pipeline releases: Pigging operations are conducted to assist in product transfer and product separation, as well as for maintenance activities. A pig is a physical device which varies in size and can be made of a variety of materials such as plastic, urethane foams, and rubber. Pigs can also be solid, inflatable, foam, or made of a viscous gel. The specific design of a particular pig depends upon the pipeline as well as the purpose of the pigging operation. Three types of pigging operations occur in pipelines at OGS field production and processing sites: product transfer, product separation, and maintenance. Pigging following product transfer is used to remove residual product from the pipeline after loading occurs. Pigs can also be used for product separation to transport more than one product, such as oil, gas, or condensate as well as for maintenance activities such as pipeline cleaning, gauging, or dewatering. During pigging operations, a pig is inserted into the pipeline and is forced through the pipeline by a compressed gas, such as nitrogen or pumped down a pipeline by the products being handled. When the pig gets to the end of the line, it is trapped in a receiver. The gas is then bled off from behind the pig. The initial depressuring of the pipeline, if vented to the atmosphere, rather than to a flare or incinerator, may involve uncontrolled blowdown emissions primarily consisting of VOC, HAPs, and H₂S. The emission rate in a blowdown is a function of the product in the pipeline, the amount of piping and equipment manifolded into the system, line pressure, the frequency of equipment discharges, and the blowdown system controls employed. The frequency of blowdowns also depends on the operational conditions of any given site. Based on a Tier II evaluation of BACT for compressor blowdowns, if the total uncontrolled VOC emissions from compressor blowdowns and other high potential uncontrolled sources at the site equals 10 tpy or greater, then these emissions should be routed to a control or recovery device with a destruction or capture efficiency of at least 95 percent (flares or VRSs).

In addition to low-pressure pipeline releases, as during pigging, many oil and gas pipelines and pipe segments, and vessels maintain a higher pressure, often greater than 30 psig. For higher pressure blowdowns when a pressurized gas is released to atmosphere the mass flow rate is proportional to the pressure differential but the exit velocity remains choked at sonic velocity (approx. 1,100 ft/sec) until the upstream piping pressure just before the release fall to below 30 psig.

4. Tank and Vessel Degassing: MSS requirements for depressurizing, draining, and degassing process equipment, equipment opening, tank and fugitive component maintenance, and vacuum truck loading continue to be evaluated based on the refinery and chemical plant permit reviews. All OGS MSS applications represented control of very high vapor pressure compounds, where vapor pressures equal or exceed 14.7 psi.
5. Other MSS: Various other activities occur at OGS to ensure equipment is kept in good working order. These include many incidental lubrication and similar actions which result in negligible releases of air contaminants, such as: lubrication oil and oil filter changes for engines and turbines; sparkplug changes; replacement of oxygen sensors; compression checks; lubrication oil leak repairs; engine overhauls; boiler refractory replacements; boiler and heater cleanings; heat exchanger cleanings; and pressure relief valve testing's. Other maintenance activities occur to ensure the process equipment operates at optimum levels by replacing treatment chemicals, catalysts, and filters. In all of these circumstances, the executive director does not anticipate any quantifiable emission releases which are otherwise not accounted for above.

N. Combined Emission Control

Oil and gas sites can have a variety of facilities that when combined have a significant number process vents emitting VOC in volumes and concentrations that are worth recovering the resource or become reasonable and appropriate to control. Where facilities are generating waste gas streams that contain more than 1 percent VOC and their combined emissions have the potential to emit more than 25 tpy of VOC, vapor recovery or oxidation or combustion control is mandated for these streams. The TCEQ strongly encourages vapor recovery where plausible and the gas capture and use is possible (i.e. gas pipelines or storage is available). Where recovery is not possible oxidation or combustion control of waste gas streams with more than 1 percent VOC is being mandated for the smaller streams. The cost of flare control has been determined to be reasonable for storage tank and loading streams of 5 tpy or more. With appropriate sizing a flare or other combustion control can accommodate routing of multiple smaller streams to the same control for the cost of piping or piping with a fan or compression to direct the gas.

O. Exclusions

The following units and operations were excluded for various reasons for consideration under the standard permit:

1. Sulfur Recovery Units (SRU) were not covered because it was discovered that when the SRU was pulled out of service for maintenance operations that the emissions typically exceed the PSD significance levels, and cannot be authorized by a PBR or standard permit. The only way to prevent triggering PSD for the site is for the OGS to build a redundant SRU to switch over during maintenance operations. Since the reviewed permitted OGS did not reveal any dual SRU units, it was concluded by the executive director's staff that the industry was reluctant to invest in the capital outlay, and consequently SRUs were excluded from the evaluation.

2. Carbon Dioxide Hot Carbonate Processing Units were excluded since the executive director's staff was not able to obtain sufficient processing and emission data for production, or maintenance, startup, and shutdown emissions on these units from applications it reviewed. As a result the executive director's staff was not able to evaluate these units.
3. Water Injection Facilities are subsurface facilities that are involved in waste disposal activities, which are beyond the scope of the OGS production processes at the sites. Instead, many of these facilities and operations can claim PBR, §106.351. In EPA's determination regarding site definition, it was limited to surface equipment, and this further supports the executive director's position.
4. The Transfer of Liquefied Petroleum Gases, Crude Oil, or Condensate by Railcar, or Marine Barges was also excluded as these operations were not found at sites in our review because larger OGS use pipeline transfer for economic reasons. However, if these operations occur on a small scale, other PBRs may be claimed, such as by §106.261 and §106.262.
5. Sour Water Strippers were not evaluated for protectiveness since they are associated with sulfur recovery units, and SRUs have been excluded from this standard permit. Sour water strippers are used to remove H₂S, a major form of sulfur compounds in sour petroleum from the water before handling and disposal were not evaluated.

V. APPLICABLE STATE AND FEDERAL REGULATIONS

A. State Regulations

All facilities and sources in Texas must comply with various requirements in 30 TAC Chapter 101, General Rules. The commission notes the most common parts of this chapter affecting OGS are Subchapter B, Emission Events, Reporting, and §101.4, Nuisance. Potential nuisance conditions do not only occur with oil and gas from odors or smoke, but in many cases in-plant roads work areas traffic and activities may generate substantial dust problems. Where necessary, operators are reminded that sufficient care and controls must be taken with all material handling and traffic which may cause dust so as to not cause a nuisance.

All sites in Texas must comply with opacity limitations in 30 TAC Chapter 111, Control of Air Pollution from Visible Emissions and Particular Matter, including the 20 percent opacity requirement and appropriate compliance demonstrations.

All OGS, especially sour sites, must ensure compliance with the ambient air standards in 30 TAC Chapter 112, (Control of Air Pollution from Sulfur Compounds). The property-line determinations must show compliance with SO₂ property-line standards ranging from 715 µg/m³ to 1021 µg/m³ (0.28 ppmv in Galveston or Harris Counties, 0.32 ppmv in Jefferson or Orange Counties, and 0.4 ppmv for the remainder of the state) and H₂S standards range from 108 µg/m³ to 162 µg/m³ (depending on impacts occurring a residences, businesses or on commercial property). These standards were evaluated and this proposal relies on using the most stringent of standards so that a simplified set of acceptable emission tables could be developed. Sulfur recovery under Chapter 112 is not addressed here as no SRUs will be allowed under the standard permit.

In addition, sites in non-attainment and near non-attainment counties must comply with various standards in 30 TAC Chapter 115, (Control of Air Pollution from Volatile Organic Compounds) for VOCs and 30 TAC Chapter 117, (Control of Air Pollution from Nitrogen Compounds) for NO_x. The affected areas include the following:

Houston/Galveston/Brazoria (HGB) - Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, Waller Counties; Dallas/Ft. Worth (DFW) - Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, Tarrant Counties; Beaumont/Port Arthur (BPA) - Hardin, Jefferson, Orange Counties; and East Texas counties (ETC) - Anderson, Brazos, Burleson, Camp, Cass, Cherokee, Franklin, Freestone, Gregg, Grimes, Harrison, Henderson, Hill, Hopkins, Hunt, Lee, Leon, Limestone, Madison, Marion, Morris, Nacogdoches, Navarro, Panola, Rains, Robertson, Rusk, Shelby, Titus, Upshur, Van Zandt, Wood Counties.

The requirements in 30 TAC Chapter 115 include: Subchapter B, Storage of Volatile Organic Compounds Vent Gas Control; Subchapter C, Loading and Unloading of Volatile Organic Compounds; Subchapter D, Control of Volatile Organic Compound Leaks from Transport Vessels; and Subchapter D: Fugitive Emission Control in Natural Gas/Gasoline Processing Operations. Depending on the vapor pressure at which certain liquids are stored or transferred, and the quantity of liquids being processed, for both crude and condensate, different control devices are required to reduce or eliminate air contaminants. Further, the site's location will require more stringent controls if located in serious or severe non-attainment areas. Like other state regulations, there are exemptions depending on specific operations at a given site.

Those OGS which have combustion devices and are located in non-attainment and near non-attainment counties must comply with requirements in 30 TAC Chapter 117. For stationary, reciprocating internal combustion engines, NO_x emission limits for specified areas vary and depend on several criteria: the type of fuel being used, the horsepower of the engine, and the date of modification (modification of an existing facility as defined under 30 TAC §116.10), reconstruction, or relocation. The compliance date, which determines when a given engine is subject, will also vary. Additionally, there are different NO_x emissions limits based on whether a site is considered major or minor. Again, there are exceptions for when engines in a specified area are exempted from the provisions of Chapter 117.

There are also Chapter 117 restrictions that apply to water heaters, small boilers, and process heaters, which are covered under Subchapter E, Multi-Region Combustion Control, Division 3. There are applicable dates and operating parameters which will cause certain equipment to become applicable to these provisions, including but not limited to maximum Btu capacity, manufacture date, and heat output. Under Subchapter E, Division 1, Electric Generating Units are subject to limitations based on installation date, use for compensation, use in turbine exhaust ducts, and area of location.

Each provision under Chapter 117 will require different methods of reporting and recordkeeping as well and will vary depending on location and the subchapter under which a company or facility is subject.

On April 24, 2010, the commission adopted changes to 30 TAC Chapter 114, (Control of Air Pollution from Mobile Sources) to expand the Emission Reduction Incentives Grants Program of the Texas Emissions Reduction Plan.

These changes include projects related to engines used for natural gas recovery. This means if an engine can be retrofitted or replaced to reduce NO_x emissions and the engine qualifies for the program, a certain amount of reimbursement is possible based on the amount of reductions achieved. The program is applicable to 41 counties in Texas, which are nonattainment counties or affected counties.

B. Federal Ambient Air Standards

National Ambient Air Quality Standards (NAAQS) must also be complied with at a site’s property line. There are numerous NAAQS for air contaminants which are released at OGS. As appropriate, standards are converted from the promulgated averaging period to an equivalent 1-hour basis for use with the emission tables. Variables for SCREEN modeling were relied upon for this conversion (30-min same as 1 hr, 3-hr adjusted by 0.9, 8-hr by 0.7, 24-hr by 0.4, and annual by 0.08). Specifically of interest is the 1-hr NO_x standard of 188 µg/m³ (100 ppmv), which became effective on April 12, 2010. Other pollutants with NAAQS and relevant averaging periods are included in the table below.

C. State Property-Line Standards and NAAQS

Applicants must demonstrate compliance with the most restrictive of all applicable state and federal property-line standards for the following pollutants: H₂S, SO₂, CO, PM₁₀, and NO_x. Based on the discussion above, the assessment of applicable limits is summed in the following table:

State and Federal Regulatory Standards

Compound (µg/m ³)	30-min Harris & Galveston	30-min Jefferson & Orange	30-min statewide	30-min residential, business or commercial	1-hr	3-hr	8-hr	24-hr	Annual
H ₂ S			162	108					
SO ₂	715	817	1,021		196	1,300		365	80
NO _x					188				100
CO					40,000		10,000		
PM ₁₀								150	
PM _{2.5}								35	15

The designated value (bolded) that should be used for the hourly emission rate limits is based on the lowest (controlling) modeling concentration for any standard, assuming continuous emissions of that air contaminant. For H₂S, the regulatory standards are all based on 30-min averages, so the worst-case 1-hour equivalent should be used for a protectiveness and compliance determination. With substantial variability in time periods during which SO₂ emissions occur, if all emissions can meet the most restrictive designated value of 196 µg/m³, no further review should be needed. CO was initially evaluated and determined to have expected impacts well below the NAAQS so no further evaluation was necessary. PM₁₀ and PM_{2.5} emissions from OGSs are typically small in magnitude, and no further evaluation was necessary after an initial evaluation. Additionally, PM_{2.5} emissions at OGSs are due to combustion. Details of the regulatory evaluation by the commission are discussed later in this document.

D. Other Federal Regulations

Federal standards applicable to OGS can be found in 40 CFR Parts 60, 61 and 63 (NSPS, NESHAPs, and MACT standards, respectively). Since the OGS PBR and standard permit were last revised, several federal standards applicable to OGS have been adopted and proposed. The proposed PBR and standard permit are consistent with the existing federal standards as much as possible. Sources (that is, facilities) subject to MACT standards are classified as either major sources or area sources. Major sources are sources that emit 10 tpy of any of the listed individual HAP, or 25 tpy of a mixture of HAPs. Area sources of HAPs are not major sources of HAPs. Though emissions from individual area sources are often relatively small, collectively their emissions can be of concern, particularly where large numbers of sources are in heavily populated areas. Most, if not all of, the federal rules that can apply to OGS are discussed briefly below. The brief discussions are not intended to replace familiarity with the federal rules, as the EPA has recently been actively changing existing federal rules, proposing new federal rules, and adopting both the changes and new rules, including federal rules that are associated with or can be associated with OGS. Additionally, the EPA is reviewing OGS drilling operations which are beyond the scope of the OGS standard permit and PBR rules. Given the recent scope of changes to and adoptions of NSPS and MACT rules associated with OGS and in general, the commission believes providing detailed descriptions of the federal rules would create confusion in the future between updated and new federal rules in comparison to this background document. Additionally, the commission believes that trying to explain some of the federal rules in more detail would add a level of detail that is beyond the scope of purpose for this background document.

1. Oil and Natural Gas Production (MACT HH): National Emission Standards for Hazardous Air Pollutants for Source Categories from Oil and Natural Gas Production Facilities applies to oil and gas production facilities located at area sources and major sources of HAPs. For major sources of HAPs, the rule applies to glycol dehydration units, tanks with potential for flash emissions, certain fugitive component emission sources at natural gas processing plants, and compressors in volatile hazardous air pollutant service which are located at natural gas processing plants, unless exemptions apply. For area sources of HAPs, the rule applies to triethylene glycol (TEG) dehydration units for which controls are required at certain trigger levels.
2. Transmission and Storage (MACT HHH): National Emission Standards for Hazardous Air Pollutants from Natural Gas and Transmission and Storage Facilities applies to natural gas transmission and storage facilities that transport or store natural gas prior to entering pipeline to a local distribution company or to a final end user if no local distribution company, as specified in the rule. For major sources of HAPs, the rule applies to glycol dehydration units, unless exemptions apply. There are no requirements for area sources of HAPs in the rule.
3. Stationary Reciprocating Internal Combustion Engines (RICE) (MACT ZZZZ): National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines applies to RICE engines that are located at major sources and area sources of HAPs, unless exemptions apply. Stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work energy and which is not mobile.

4. Petroleum Liquids Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973 and Prior to May 19, 1978 (NSPS Subpart K): The rule applies to each storage vessel for petroleum liquids which has a storage capacity greater than 40,000 gallons. The rule does not apply to storage vessels for petroleum or condensate located at drilling and production sites prior to custody transfer.
5. Petroleum Liquids Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978 and Prior to July 24, 1984. (NSPS Ka): The rule applies to each storage vessel containing petroleum liquids with a storage capacity greater than 40,000 gallons for which construction, reconstruction, or modification commenced after May 18, 1978 and prior to July 24, 1984. The rule does not apply to each storage vessel with a capacity less than 420,000 gallons used for petroleum or condensate prior to custody transfer.
6. Volatile Organic Liquids Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (NSPS Kb): The rule applies to each storage vessel containing volatile organic liquids with a storage capacity greater than or equal to 75 cubic meters (approximately 19,800 gallons) for which construction, reconstruction, or modification commenced after July 23, 1984, except that storage vessels are exempt based on capacity and maximum true vapor pressure of the liquid being stored, as specified in the rule. Pressure vessels are exempt, as specified. Storage vessels at specified industry types are exempt. Storage vessels permanently attached to mobile vehicles are exempt, as specified. Each storage vessel with a design capacity less than or equal to 1,589.874 cubic meters (approximately 420,000 gallons) storing petroleum or condensate prior to custody transfer is exempt, as specified.
7. Stationary Gas Turbines (NSPS GG): Standards of Performance for Stationary Gas Turbines applies to stationary gas turbines that have a peak load equal to or greater than 10 million Btu/hr based on the lower heating value of the fuel and that commenced construction, modification, or reconstruction after October 3, 1977, except that some turbines may be exempt from some of the rule requirements, as specified. Stationary combustion turbines subject to the requirements of NSPS KKKK (discussed below) are exempt from NSPS GG requirements.
8. Equipment Leaks of VOC From Onshore Natural Gas Processing Plants (NSPS KKK): Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants applies to sources at onshore natural gas processing plants that commenced construction, reconstruction, or modification after January 20, 1984, as specified and defined, and to compressor stations, dehydration units, sweetening units, underground storage tanks, field gas gathering systems, and liquefied natural gas units if located at onshore natural gas processing plants. Exceptions for the rule apply as specified. Sources covered by NSPS Subparts VV or GGG are excluded from NSPS KKK.
9. Onshore Natural Gas Processing SO₂ Emissions (NSPS LLL): Standards of Performance for Onshore Natural Gas Processing; SO₂ Emissions applies to natural gas sweetening units and natural gas sweetening units followed by sulfur recovery units that commenced construction or modification after January 20, 1984 and that acid gas. Sites with a design capacity of less than 2 long tons per day of hydrogen sulfide (as sulfur) have only recordkeeping requirements.

Sites that completely re-inject acid gas into oil-or-gas-bearing geologic strata or that does not release acid gas to the atmosphere are not required to comply with the subpart.

10. Compression ignition (CI) internal combustion engines (ICE) (NSPS IIII): Standards of Performance for Stationary Compression Ignition Internal Combustion Engines applies to manufacturers, owners, and operators of stationary compression ignition internal combustion engines as specified in the rule. Several applicability dates are listed in the rule and depend on engine size, date of manufacture or remanufacture of the engine, and use of the engine, as specified in the rule. Exemptions apply as specified in the rule.
11. Stationary spark ignition (SI) internal combustion engines (ICE) (NSPS JJJJ): Standards of Performance for Stationary Spark Ignition Internal Combustion Engines applies to manufacturers, owners, and operators of stationary spark ignition internal combustion engines as specified in the rule. Several applicability dates are listed in the rule and depend on engine size, engine type, date of manufacture or remanufacture of the engine, and use of the engine, as specified in the rule. Exemptions apply as specified in the rule. In general, the rule is applicable to engines manufactured, modified, or reconstructed after June 12, 2006.
12. Standards of Performance for Stationary Combustion Turbines: (NSPS KKKK) Standards of Performance for Stationary Combustion Turbines applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu; heat input determination does not including heat recovery or duct burners) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005. Exemptions apply as specified in the rule.
13. National Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (MACT YYYY): National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines applies to existing, new, or reconstructed stationary combustion turbines at major sources of HAPs. Exemptions apply as specified in the rule.
14. National standards for equipment leaks (MACT H): National Emissions Standards for Organic Hazardous Air Pollutants for Equipment Leaks applies to pumps, compressors, agitators, pressure relief devices, and other specified equipment that operate in organic service 300 hours or more during a calendar year within sources subject to MACT subparts that reference MACT H. Exemptions apply as specified in the rule.
15. National standards for separators: National Emission Standards for Oil-Water Separators and Organic-Water Separators applies to oil-water and organic-water separators for which an NSPS or NESHAP subpart or another MACT subpart references MACT VV.
16. National standards for equipment leaks (NESHAP V): National Emission Standard for Equipment Leaks applies to pumps, compressors, pressure relief devices, sampling connection systems, and other sources operating in volatile hazardous air pollutant service.

17. General provisions (MACT A, NESHAP A, and NSPS A): MACT A, NESHAP A, and NSPS A apply in general. For example, NSPS KKK allows for flares for compliance and references the general control device and work practice requirements for flares under NSPS A, 60.18.
18. Compliance Assurance Monitoring and Periodic Monitoring: Compliance assurance monitoring (CAM) is a federal monitoring program implemented under the authority of 30 TAC Chapter 122, (Federal Operating Permits), Subchapter G to establish minimal monitoring requirements for state and federal rules for emission units (emission units as defined in Chapter 122) that lack sufficient monitoring, testing, and recordkeeping requirements to demonstrate compliance with emission limitations or standards. Since OGS authorized under PBR Level 2 and standard permit can also be applicable to the federal operating permit program, CAM should be considered.

Periodic monitoring (PM) is a federal monitoring program implemented under the authority of 30 TAC Chapter 122, Subchapter G and applies to emission units at sites with emission limitations or standards. An emission unit requires PM if the emission limitation or standard that the unit is subject to does not specify PM (which may consist of recordkeeping) that is sufficient to yield reliable data from a relevant time period that is representative of the emission unit's compliance with the applicable requirement and testing, monitoring, reporting, or recordkeeping sufficient to assure compliance with the applicable requirement. Since OGS authorized under standard permit can also be applicable to the federal operating permit program, PM should be considered.

Some requirements that could be considered CAM and PM requirements were added to the OGS PBR and standard permit rules. The CAM and PM requirements in the OGS rules do not trump more stringent CAM and PM requirements under the oil and gas GOPs and in SOPs. Please note that case-by-case review, including case-by-case review of CAM and PM, and authorizations other than PBRs and standard permits are not allowed under GOPs.

VI. PROTECTIVENESS REVIEW

An OGS will process gases and liquids associated with the production, conditioning, processing, and pipeline transfer of OGS fluids and gases. OGS use a variety of process equipment which can be arranged in an almost infinite number of possible configurations. Depending on the region in Texas, the composition of the gas or liquids varies greatly. In some areas of Texas, H₂S is required to be extracted from the process stream. These various regions have sour sites that may have significant H₂S and SO₂ emissions. Because of these various types operations, equipment, configurations, and composition it was difficult to develop emission limits for each process type or equipment used in a PBR and standard permit that were more comprehensive and demonstrate protectiveness for authorization of the common OGS in Texas. The protectiveness evaluation is even more important when an OGS is located in close proximity to the general public. Therefore, the executive director staff modeled OGS emissions as a unitized maximum concentration based on stack height and the distance from the stack to the nearest off property receptor or property line as a function of each compound's Effects Screening Level (ESL) or equivalent regulatory limit.

A. Effects Screening Levels

The ESLs are guideline concentrations derived by the executive director's Toxicology Division and used to evaluate ambient air concentrations of constituents. ESLs are based on data concerning health effects, the potential for odors to be a nuisance, effects on vegetation, and corrosive effects. They are not ambient air standards. If predicted or measured airborne levels of a constituent do not exceed the screening level, adverse health or welfare effects are not expected. If ambient levels of constituents in air exceed the screening levels, it does not necessarily indicate a problem but rather triggers a more in-depth review, which is the purpose of the case-by-case permitting process. The current ESL list is available through:

<http://www.tceq.state.tx.us/assets/public/implementation/tox/esl/list/october2009.pdf>.

Current hourly and annual ESLs which are likely to be applicable to OGS from both production and MSS activities include the following common compounds and are summarized in the Effects Screening Level table below. Emissions for treatment chemicals (including but not limited to, amines, glycols, and methanol) may need to be evaluated if used in sufficient quantities. These chemicals' ESLs vary, so the current list should be referenced for specific information.

Effects Screening Levels Table

Substance	Hourly Concentration ($\mu\text{g}/\text{m}^3$)	Annual Concentration ($\mu\text{g}/\text{m}^3$)
Crude oil	3,500	350
Condensate	3,500	350
Natural gas	18,000	1,800
Benzene	170	4.5
Toluene	640	1200
Ethylbenzene	740	74
Xylene	350	180
Cyclohexane	420	42
Methylcyclohexane	4000	400

VOC sampling data from the Air Quality Research project HO51C, *Evaluation of VOC Emissions from Flash and Condensate Tanks*, and other industry supplied information was reviewed by the Toxicology Division, and ESLs were developed for common mixtures of chemicals at OGS: natural gas, crude oil and condensate. The ESL developed by the Toxicology Division for condensate has recently been updated to $3,500 \mu\text{g}/\text{m}^3$. The Toxicology Division had previously developed ESLs for crude oil at $3500 \mu\text{g}/\text{m}^3$, and natural gas at $18,000 \mu\text{g}/\text{m}^3$.

The short-term ESLs for crude oil and condensate ($3,500 \mu\text{g}/\text{m}^3$) were set based on the weight percent of components in typical crude oil (raw data available upon request). The ESLs were developed by calculated by each component's weight percent and its respective ESL using a formula for the derivation of a chemical product.

Accordingly, an ESL of the chemical product can be derived by the following formula where f_n equals the fractional quantity of component 'n' in product X, and ESL_n equals the ESL for component 'n':

$$X = \frac{1}{f_a / ESL_a + f_b / ESL_b + f_c / ESL_c + \dots + f_n / ESL_n}$$

The annual ESL for benzene is substantially lower than any of the corresponding ESLs for other air contaminants expected to be emitted at an OGS. To analyze the annual acceptable emissions of benzene, both the hourly and annual impacts must be evaluated for protectiveness. Additional information on the development supporting document for benzene is available through:

http://tceq.com/assets/public/implementation/tox/dsd/final/benzene_71-43-2_final_10-15-07.pdf.

B. Ambient Air Standards

There are numerous state and National Ambient Air Quality Standards (NAAQS) applicable to the emissions associated with an OGS, including NO₂ (hourly 188 micrograms per cubic meter (µg/m³), annual NAAQS, 100 µg/m³; CO (hourly NAAQS 40,000 µg/m³ and 8-hour NAAQS 10,000 µg/m³), sulfur dioxide (SO₂) (new hourly NAAQS 196 µg/m³, 3-hour NAAQS 1300 µg/m³, 24-hour NAAQS 365 µg/m³, and annual NAAQS 80 µg/m³, most stringent state 30-minute standard 715 µg/m³), particulate matter (PM) less than or equal to ten microns in diameter (PM₁₀) (24-hour NAAQS 150 µg/m³, PM less than or equal to 2.5 microns in diameter (PM_{2.5}) (24-hour NAAQS 35 µg/m³, annual NAAQS 15 µg/m³). H₂S does not have a NAAQS, but is regulated by 30 TAC Chapter 112, Control of Air Pollution from Sulfur Compounds (statewide standard is 162 µg/m³, with the most stringent state standard at 108 µg/m³).

C. Groups of Similar Releases

Based on the variability of equipment and operations, it was determined that emission releases would be grouped for dispersion modeling to predict acceptable off-property impacts. This analysis was compared to expected emission types and quantities for assessment of protectiveness and compliance with state and federal emission standards from common OGS. The "generic" approach could also be used to show the appropriate insignificance or acceptability of various operations, providing additional flexibility for OGS seeking authorization under the PBR or standard permit. The groups of similar emission releases were chosen based on similar parameters of the release points. The executive director staff's analysis identified four distinct groups: process unit vents and similar stacks, fugitive components, tanks, and loading of trucks; blowdowns and similar MSS activities; combustion units; and thermal destruction devices (flares).

To ensure a representative, reasonable, worst-case set of dispersion parameters to evaluate, the executive director's staff researched permit files. One of the steps in identifying and modeling a set of conservative sources was to generate a list of OGS authorized by the current standard permit with large emissions. The Air Permits Division document and data management systems were initially searched, but no consistent results could be found to develop a firm list of sources with larger emissions. Instead, the executive director staff reviewed the agency's air emission inventory from 2004 based on SIC code and authorization type. The list was separated and sorted (highest to lowest) for: NO_x, VOC, H₂S, and SO₂ emission quantities.

High emission value sites were researched and the standard permits identified at a dozen or more sites on the high end of the list. Many of the facilities at these OGS were used to confirm appropriate dispersion parameters and, subsequently, confirm if these types of OGS could meet the PBR and standard permit conditions.

D. Modeling Procedures and Impacts Analysis

The air quality impacts analysis considered numerous variables including: emission source types and associated emission parameters; building wake effects (downwash); meteorological data; receptor grid, and model use and techniques. Generic modeling was conducted to account for sources at all oil and gas production sites. Tables 2 – 5F in paragraph (m) were created from concentrations predicted by the Industrial Source Complex Short Term 3 (ISCST3) (Version 02035) model. The ISCST3 model is based on the Gaussian distribution equation and is inherently conservative due to the main simplifying assumptions made in its derivation: conditions are steady-state (for each hour, emissions, wind speed, and direction are constant) and the dispersion from source to receptor is effectively instantaneous; there is no plume history as model calculations in each hour are independent of those in other hours; mass is conserved (no removal due to interaction with terrain, deposition, or chemical transformation) and is reflected at the surface; and plume spread from the centerline follows a normal Gaussian distribution and only vertical and crosswind dispersion occurs, dispersion downwind is ignored. In addition, the model provides conservative results for short distances and low-level emissions and tends to over-predict ground-level concentrations. The model was applied in a screening mode to ensure predictions were conservative (higher predicted concentrations) and applicable for any location in the state. The rural dispersion option was used as it would be rare for oil and gas facility plumes to be influenced by urban dispersion effects. All emissions sources were co-located on a single site, in order to minimize bias due to source configuration and wind direction. This technique also provides conservative results since the cumulative impact from all sources is maximized.

Based on comments, the initial modeling analysis was updated to include predicted concentrations out to a distance of 5500 feet for all sources. The combustion unit modeling was updated to include additional ranges of engines. Subsequent review of the pipeline blowdowns parameters used in the previous analysis were determined not to be representative of the activities occurring. The compressor blowdown parameters were determined to be representative for both pipeline and compressor blowdowns. The pipeline blowdown results are no longer necessary and are removed from the results. This modeling supersedes previous modeling results and the appropriate tables were updated and results used to develop reasonably conservative emission limits. Each source was modeled separately at a unitized emission rate of one pound per hour. This technique determined a unitized maximum predicted ground-level concentration (GLCmax) for each source in units of micrograms per cubic meter per pounds per hour. To determine the allowable emission rate for each contaminant, the applicable ESL or standard can be divided by the generic GLCmax. The Tables represent modeled concentration from the following sources.

Fugitive sources comprise all fugitive emissions from a representative oil and gas site. Fugitive emissions were represented as three sources: a circular area source with a 1 meter release height and 9 meter diameter; a point source with a 3 meter release height; and a point source with a 6 meter release height. Lowest level fugitive emissions (at about 1 meter) occur at various locations within a plant site. Since the resulting emissions are usually well distributed throughout a site and not released through standard stacks, an area source representation is appropriate.

The circular area source type was selected to minimize bias of any one wind direction or source orientation. Similarly, the loading and storage tank fugitive's emissions do not release to the atmosphere through standard stacks but generally are not distributed throughout a site. The loading and tank fugitive emissions are represented by the point source characterization using pseudo-point source parameters and are co-located with the circular area source.

Process vent stacks sources are representative of stacks or vents not associated with truck loading or storage tanks, such as amine treaters and glycol dehydration units. Stack parameters were derived from a review of permitted sources. Seven complex oil and gas sites were reviewed resulting in a compilation of source parameters for 21 facilities. Of the 21 facilities reviewed, stack heights ranged from 12 to 39 feet, stack diameters ranged from 0.05 to 3.5 feet, exit velocities ranged from 1 to 90 feet per second, and temperatures ranged from 80 degrees F to 800 degrees F. Reasonable worst-case parameters for air dispersion modeling were derived from this review. A stack flow rate of 500 actual cubic feet per minute (acfm) at 120 degrees F was used in the analysis. A stack diameter of 1 foot was modeled with an exit velocity 10.6 feet per second. The stack heights modeled ranged from 10 feet to 60 feet. These sources were represented as point sources.

Compressor blowdown stacks and pipeline blowdown are representative stacks used for the temporary venting of a gas compressor or temporary venting of a gas pipeline. Stack parameters were derived from a review of industry sources. Sites with the highest planned MSS emissions of the sites reviewed were selected in order to derive reasonable worst-case modeling parameters for blowdowns. A stack flow rate of 100 acfm at ambient temperature was used in the model. A stack diameter of 6 inches was modeled with an exit velocity of 8.5 feet per second. The stack heights modeled ranged from 3 feet to 20 feet. It was determined that stack-tip downwash was not appropriate due to the small diameter of the stacks and the short duration of the activity (generally less than 30 minutes).

After subsequent review of the blowdown parameters used in the previous analysis, the modeled parameters were determined not to be representative of the activities occurring under high pressure. The modeling results were updated to include more representative parameters for blowdowns with pressure greater than or equal to 30 pounds per square inch gauge (psig). Sources were modeled as representative stacks used for the temporary venting of a gas compressor or temporary venting of a gas pipeline under high pressure. Reasonable worst case stack parameters were derived from a review of industry sources, and two source configurations were modeled. A stack with a height of 6 feet and a diameter of 4 inches was modeled with an exit velocity of 550 feet per second (fps), and a stack with a height of 10 feet and a diameter of 6 inches was modeled with an exit velocity of 550 fps. A minimum stack height of 6 feet is expected due to safety concerns. The initial period of the blowdown will have the greatest amount of pressure resulting in the largest exit velocity and highest plume rise. Near the end of the blowdown period, the pressure will have decreased resulting in less exit velocity and less plume rise. For this reason, an exit velocity of 550 fps is reasonable given the initial velocity expected is 1100 fps and will decrease over time as the pressure decreases. It was determined that stack-tip downwash was not appropriate due to the small diameter of the stacks, high exit velocity, and the short duration of the activity (generally less than 30 minutes). These higher pressure (>30 psig) blowdown scenarios were evaluated and demonstrated dramatically increased dispersion parameters, reducing potential impacts.

For higher pressure blowdowns when a pressurized gas is released to atmosphere the mass flow rate is proportional to the pressure differential but the exit velocity remains choked at sonic velocity (approximately 1,100 ft/sec) until the upstream piping pressure just before the release falls to below 30 psig. The model was run at a conservative exit velocity of (550 ft/sec) one half of the sonic velocity through a 6 inch diameter opening to the atmosphere directed vertically. Based upon the submitted information, two release scenarios for a vertical 6 foot and a 10 foot release height for higher pressure blowdowns from pipelines were developed and added to paragraph (g)(3) and (h)(3) in the PBR and paragraph (h)(3) in the SP. These scenarios are for pressurized gas that is rapidly released with the piping initial pressure exceeding 30 psig. These scenarios assume no liquids are released, only vapors.

Combustion units are representative of all internal combustion processes associated with reciprocating engines. Reasonable worst-case stack parameters were derived from an industry review of sources. Six engine ranges are represented in the modeling. Engine exhaust stacks were modeled as point sources with release heights of 8, 10, 12, 14, 16, 18, 20, 25, 30, 35, and 40 feet. The engine ranges and exhaust parameters are listed below:

Table A. Engine HP ranges and Exhaust parameters			
Source Group	Horsepower Range	Flow (acfm)	Diameter (inches)
ENG1	Less than 250	984	6
ENG2	250 to 500	2459	8
ENG3	500 to 1000	4920	10
ENG4	1000 to 1500	8198	12
ENG5	1500 to 2000	11842	12
ENG6	Greater than 2000	16330	16

Thermal destruction devices are representative of all processes associated with flares and other thermal destruction devices. Reasonable worst-case stack parameters were derived from a review of industry thermal control devices. Numerous authorization files were evaluated for thermal destruction devices, including thermal oxidizers, boilers, heaters, flares, and fire box incinerators. The most common facilities found were flares. Flares continuously burn a pilot flame, resulting in small amounts of NO_x, CO, SO₂, and PM₁₀/PM_{2.5} being emitted. When a process stream is being destroyed, slightly higher amounts of these pollutants are released. In addition, when flares are used to destroy process waste streams or during planned MSS, some amount of VOCs are released, which may contribute to off-property impacts. More importantly, when a flare is used at a sour site, sulfur compounds (primarily H₂S) convert to SO₂, and, depending on the waste streams, may potentially emit significant amounts of this criteria air contaminant.

Emission rates and stack parameter data for thermal destruction devices were gathered for approximately 20 sites. The assumptions used in developing the reasonable worst-case parameters were a minimum energy value of 200 British thermal unit per standard cubic foot (btu/scf) in accordance with NSPS in 40 CFR §60.18, and a minimum height of 20 feet. Five sites of those reviewed had low flow values ranging from 691 to 3,129 standard cubic feet per minute (scfh).

These were averaged to derive a reasonable low flow value of 2,400 scfh. Flares were modeled as point sources with temperature of 1273 Kelvin (K) (1832 degrees F), exit velocity of 20 meters/sec (66 ft/sec), release heights of 20, 30, 40, 50, and 60 feet, and a diameter of 6 inches. The values for the exit temperature and velocity are default values for modeling flares. Many sites have flares or similarly designed thermal destruction devices to control VOCs during production and planned MSS. Since the dispersion characteristics of these units have higher flow, thermal buoyancy, and usually higher release heights to process vents, these factors combine to have greater dispersion, and thus higher emissions would be allowed.

The modeling analysis used a polar receptor grid with 36 radials spaced every 10 degrees from true north. Receptors were located on each radial at distances of 50, 100, 150, 200, every one hundred feet out to 3,000 feet, and every five hundred feet out to 5500 feet. To streamline the modeling analysis, surface meteorological data from Austin and upper-air data from Victoria for the years 1983, 1984, 1986, 1987, and 1988 was used. Since the analysis is primarily for short-term concentrations, this five-year data set would include worst-case short-term meteorological conditions that could occur anywhere in the state. The wind directions were set at 10 degree intervals to coincide with the receptor radials. This would provide predictions along the plume centerline which is a conservative result.

Based on a review of existing sites, no downwash structures were included in the analysis. No significant structures would likely exist at these types of sites that would influence dispersion. In addition, downwash is not applicable to area sources.

The modeling analysis document can be found through the Air Permits Remote Document Server, in the New Source Review General (NSRG) library under document number 10989. The modeling files can be found in the NSRG library under document number 10991. The result of this analysis was used to develop tables for confirmation of acceptable emissions for any applicable standards and ESLs. These tables are included in the standard permit and PBR as one of three possible tools available to the regulated community to demonstrate protectiveness.

The commission expanded the evaluation to approximately 1 mile (5,500 feet) based on three factors: 1) the commission's consideration of distance limits for contiguous properties and operationally related facilities; 2) the conservative nature of the model and modeling approach as previously discussed; and 3) the commission's intent to establish conservative emission rates and site-wide limits to address the requirements of various air quality permitting programs. In addition, it is the commission's experience that worst-case modeled concentrations from the facilities authorized by this rule do not occur under actual operating and meteorological conditions and are not measured at the values predicted at distances beyond approximately 1/2 mile.

E. How to use Modeling Results

To use the modeling tables, a corresponding lb/hr maximum emission rate can be determined using the following equations. This equation is similar to that currently identified in §106.262 ($E = L/K$), but with different parameters.

For an ambient air standard: $E_{\max} = P/G$ where E_{\max} is the maximum hourly emissions acceptable (lb/hr); P is the appropriate property line standard ($\mu\text{g}/\text{m}^3$); and G is the value from the Generic Emissions Tables at the emission point's release height and distance to property line ($[\mu\text{g}/\text{m}^3]/[\text{lb}/\text{hr}]$).

For health effects review: $E_{\max} = \text{ESL}/G$ where E_{\max} is the maximum acceptable hourly emissions (lb/hr); ESL is the current published effects screening level for the specific air contaminant ($\mu\text{g}/\text{m}^3$); and G is the value from the Generic Emissions Tables at the emission point's release height and distance to property line ($[\mu\text{g}/\text{m}^3]/[\text{lb}/\text{hr}]$).

Most OGS have more than one facility or release point of emissions. To account for this variability, instead of co-locating all sources at the most conservative point of release to establish acceptable emission rates and confirm compliance with the PBR or standard permit, OGS may use a weighted fraction method. The four tables predict impacts based on various dispersion characteristics, with greater acceptable emissions from various sources (smallest to largest): fugitives, blowdowns, process vents, combustion devices, and flares. Since many of these facilities emit air contaminants simultaneously, the corresponding contribution of each release must be considered to ensure acceptable emissions. Therefore, acceptable emission limits are determined using a weighed ratio. For simultaneously emitting sources, the weighted fraction method with the above equation may be used for any combination of sources emitting the same air contaminant:

$$E_{\max} (\text{lb}/\text{hr}) = (\text{WR EPN 1}) (P/G \text{ EPN 1}) + (\text{WR EPN 2}) (P/G \text{ EPN 2}) + (\text{WR EPN 3}) (P/G \text{ EPN 3}) + \dots$$

or

$$E_{\max} (\text{lb}/\text{hr}) = (\text{WR EPN 1}) (\text{ESL}/G \text{ EPN 1}) + (\text{WR EPN 2}) (\text{ESL}/G \text{ EPN 2}) + (\text{WR EPN 3}) (\text{ESL}/G \text{ EPN 3}) + \dots$$

With minor adjustments, this same equation can be used for annual impacts evaluation. Standard practice, as those published in the TCEQ Modeling Guidance Document which may be found at

http://www.tceq.state.tx.us/permitting/air/guidance/newsourcereview/nsr_mod_guidance.html, is to multiply the hourly impact concentration by 0.08 to establish a conservative annual impact concentration. Thus, the weighted fraction equations would be:

$$E_{\max} (\text{tpy}) = (8760/2000) \{ (\text{WR EPN 1}) (P / [0.08 * G \text{ EPN 1}]) + (\text{WR EPN 2}) (P / [0.08 * G \text{ EPN 2}]) + (\text{WR EPN 3}) (P / [0.08 * G \text{ EPN 3}]) + \dots \}$$

or

$$E_{\max} (\text{tpy}) = (8760/2000) \{ (\text{WR EPN 1}) (\text{ESL} / [0.08 * G \text{ EPN 1}]) + (\text{WR EPN 2}) (\text{ESL} / [0.08 * G \text{ EPN 2}]) + \dots \}$$

where $E_{\max} (\text{lb}/\text{hr}) =$ maximum hourly emissions acceptable (lb/hr)

$E_{\max} (\text{tpy}) =$ maximum tons per year emissions acceptable (tpy)

WR EPN(x) = Emissions of each EPN divided by the sum of total emissions for all EPNs that emit that pollutant or ($E_{\text{EPN } x} / E_{\text{total}}$)

P = short term or annual (as appropriate) property line standard ($\mu\text{g}/\text{m}^3$)

ESL = current published short term or annual (as appropriate) effects screening level for the specific air contaminant ($\mu\text{g}/\text{m}^3$)

G = value from the Generic Emissions Tables at the emission point's release height and distance to property line ($[\mu\text{g}/\text{m}^3]/[\text{lb}/\text{hr}]$).

The cumulative impacts from any given OGS must be considered for protectiveness. To provide flexibility, applicants may use the weight fraction method of proportioning impacts in the same way as PBR §§106.261 and 106.262 currently use to proportion impacts from different sources at different distances. The authorizations contain several tables applicable to the type sources located at the site. This will enable an applicant to compute their emission limits for the applicable air contaminants from those sources. Each table will allow an applicant to either meet specific emission limits, or compute the specific emission limit for that type source. These tables can be used assuming 100 percent of the specific emissions are at a worst-case point (very conservative). They may also be used to compute the specific emission limit for each emission point (may involve different distances, heights, and type tables) by use of the weight fraction method, which will allow for consideration of multiple, similarly emitting sources operating simultaneously at an OGS. The most conservative approach using the worst-case source calculated from each table will result in the maximum impact allowed for protectiveness from that source without regard to other sources emitting the same compound at the same time. Using the weight fraction approach, emission limits can be established for all other type equipment emitting the same compound at the same time. If the OGSs estimated emission rates using either method are less than or equal to the calculated emission rate limit as determined from the tables, the emission are acceptable and can be authorized.

Occasionally, compressed gases from a compressor station or pipeline have to be purged for planned MSS activities, referred to as a blowdown. Emissions from blowdowns typically do not occur at the same time as regular production emission based on the representations in permit reviews. Therefore, these different operating scenarios can have different limits. In no cases should any values be generated for distances (less than 50 feet or greater than 5,500 feet) or stack heights beyond the boundaries established by a particular table.

F. Summary of Modeling Results

Various OGS activities were examined for their potential effect on public health, and the executive director staff concluded that as long as site-wide emission caps for each pollutant are not exceeded, the restrictions imposed by the PBR and standard permit are protective of public health. No “exceedances” of an ESL are expected for qualifying sites. A complete report of modeling results is available by request to the executive director.

Based on the file evaluation of previously represented emission rates from various facilities at OGS and the tables generated, the quantity of certain criteria pollutants (CO and PM₁₀), consistently meets all federal national ambient air quality standards. While NO₂ now has both an hourly and annual NAAQS, based on several examples, it appears the hourly impacts will be the limiting factor (assuming sources at an OGS operate continuously except for planned MSS). In addition, numerous speciated VOCs (BTEX, propane, butane, and others) were evaluated from both files and hypothetical cases based on concentration percentage and relative ESL. In almost every instance, the compound benzene triggered limits before any other VOC compound.

Therefore, while all records, certifications, and registrations will require emission limit calculations, certain air contaminants will not be required to confirm compliance with the impact tables. Based on the review, there are specific air contaminants with state or federal standards that must show how the emissions will meet standards, especially H₂S and SO₂ and NO₂.

Certain speciated VOC air contaminants emitted from an OGS also must be evaluated against the impact tables or other methods, particularly benzene.

G. Impacts Analysis of Air Contaminants

Based on the tables developed for site-wide OGS analysis, there is a large range of possible emissions which would be allowable and protective of public health and welfare. The executive director's staff also reviewed these possible values, and combinations of limits, against a random sample of PBR and standard permit registrations over the last 4 years. In general, the emissions from registrations have been within the limits issued, or with the installation of a vapor recovery system, could meet the issued limits.

To demonstrate the maximum acceptable emissions at various locations from various sources, the commission has included as an appendix with emission charts completed for the pollutants of interest at OGS. These charts are not intended for direct inclusion in the PBR or standard permit, nor should they be used for compliance purposes, but they are provided to give the public and regulated community an idea of the maximum amount of emissions which could be released. These tables assume that all emissions released come from the single point.

To determine when emissions from certain air contaminants need to be specifically included in a protectiveness demonstration, the commission used the generic tables to estimate the maximum acceptable hourly emissions that would not exceed any ambient standard or ESL. Additionally, the commission reviewed hundreds of OGS PBR and standard permit registrations and reports and set reasonable emission rates and site-wide caps based on the conservative predictions from the entire receptor grid of the impacts analysis. The commission restricted emission changes at existing OGS facilities to ensure continuing protectiveness of previously authorized facilities. The following paragraphs summarize the results of the commission's review.

The following are summaries of the health impacts of the regulated pollutants:

Benzene

Breathing high concentrations of benzene for a short period of time (hours) can cause dizziness, nausea, headache, and drowsiness. Repeated exposure to high concentrations for several days may adversely affect the blood. Breathing high concentrations of benzene every day for years may adversely affect your bone marrow and blood and may increase your risk for a specific type of leukemia.

Hydrogen Sulfide

Short-term exposure to low concentrations of hydrogen sulfide may cause irritation to the eyes, nose, or throat. It may also cause difficulty in breathing for some asthmatics. Brief exposures to high concentrations of hydrogen sulfide (greater than 500 ppm) can cause a loss of consciousness. Repeated or long-term low-level exposures to hydrogen sulfide may also cause signs and symptoms such as headache, fatigue, dizziness, and irritability; or neurological effects. Hydrogen sulfide also poses an offensive rotten-egg odor with an odor threshold concentration (0.008 ppm) well below the levels cause adverse health effects.

Nitrogen Dioxide (NO₂)

Short-term exposure to low concentrations of NO₂ can cause mild eye, mucous membrane, and respiratory tract irritation. Brief exposures to high concentrations of NO₂ can cause the tightness of chest or lung edema. Repeated or chronic NO₂ exposure may cause chronic bronchitis, lung edema, and emphysema of the lungs. NO₂ has a distinct odor with an odor perceptible level at 0.11 ppm.

Sulfur Dioxide (SO₂)

Short-term exposure to low concentrations of SO₂ can cause respiratory (mucous membrane) irritation. Brief exposures to high concentrations of SO₂ can cause upper airways constriction, irritation and complaints of discomfort, cough, and loss of lung function. Excessive and chronic exposure to SO₂ can cause reductions in lung function, thickened mucous layer in the trachea, and chronic respiratory disease. SO₂ has a strong suffocating odor with an odor perceptible level approximately at 0.5 ppm.

Air dispersion modeling was performed for a variety of emission source types (for example fugitives, flares, and engines) based on reasonable modeling parameters specific to each type. This modeling is not pollutant specific, meaning that it can apply to multiple compounds. Since the modeling was run with a one lb/hr basis, the units of the modeling results are micrograms per cubic meter per pound per hour, which is a concentration over a mass rate. The model was set up to give a result for combinations of emission release heights (based on reasonable height ranges for the type of emission source) and distances out to 5,500 ft. These results are shown in the PBR and standard permit Tables 2-5F in subsection (m) of each document.

These generic modeling results were combined with the most stringent concentration limits (either an effects screening level - ESL, or ambient air quality standard - AAQS concentration) for each pollutant in order to come up with an emission rate in pounds per hour. This was done by dividing the ESL or AAQS by the modeling result; a concentration divided by a concentration over a mass rate equals a mass rate. Both short term/hourly and long term/annual ESLs and AAQSs were considered.

To establish the emission limits for the PBR and standard permit, the commission looked at the sources that had the highest potential emissions of each compound. The commission then looked at the emissions at certain release heights and distances. The release heights chosen vary based on what is reasonable for each emission source type; the distances chosen are approximately 1/4 mile for PBR Level 1, 1/2 mile for PBR Level 2, and 1 mile for the standard permit.

The PBR and standard permit limits are emission caps. The commission is also asking applicants to demonstrate protectiveness for benzene, hydrogen sulfide, sulfur dioxide, and nitrogen oxides based on how close a site's emissions are to property lines and receptors. This means that in order to demonstrate protectiveness a site may be limited to even less than these caps.

The following discussion covers the logic of how the air contaminants of concern at oil and gas sites were evaluated to determine that NO_x, SO₂, H₂S, and benzene are the only air contaminants that need to be included in the pollutant by pollutant protectiveness demonstration of paragraph (k). It is important to note that contaminants not required to be included in the registration-specific protectiveness review are still held to the limits of the standard permit, just not a more stringent standard based on the protectiveness review.

The commission has determined that as long as protectiveness of these specified air contaminants is demonstrated, it can be assumed that the emissions of other contaminants are protective as long as they meet the emission limits set. For this determination, the generic modeling results were used to create pollutant specific tables that show the emission rates of specific pollutants determined to be protective of public health and welfare and meet applicable ambient air quality standards (at the listed release height and distance from the emission source to the receptor or property line). The emission rates (lb/hr) are calculated by dividing either the Effects Screening Levels (ESLs) or ambient air quality standards ($\mu\text{g}/\text{m}^3$) applicable to each specific pollutant by the modeling results ($\mu\text{g}/\text{m}^3$) per (lb/hr). Both short term and long term ESLs and air quality standards were considered. The most stringent ESLs and air quality standards were used in all analyses.

CO has a 1-hour ambient air standard of $40,000 \mu\text{g}/\text{m}^3$ and an 8-hour standard of $10,000 \mu\text{g}/\text{m}^3$, as measured at the nearest property line to the authorized facilities. The most substantial sources of CO at OGS are from engines. Using the conservative impacts evaluation table for engines, at the shortest distance (50 feet) and the lowest dispersing stack (8 feet), the maximum predicted acceptable amount of emissions from engines smaller than 250 hp would be 412 lb/hr. After a random audit of approximately 100 reviewed OGS PBR and standard permit registrations in 2010, the range of CO emissions for sites was represented to be from 0.03 lb/hr to 14 lb/hr, with an average of 4 lb/hr. Based on this information, it is extremely unlikely that any OGS will have or contribute to an exceedance of the CO 1-hour or 8-hour NAAQS; therefore, a registration-specific impacts analysis is not necessary or required by this proposal.

PM less than or equal to PM_{10} and particulate matter less than or equal to $\text{PM}_{2.5}$ have 24-hour ambient air standards of $150 \mu\text{g}/\text{m}^3$ and $35 \mu\text{g}/\text{m}^3$, respectively. Additionally, the annual ambient air standard for $\text{PM}_{2.5}$ is $15 \mu\text{g}/\text{m}^3$. For the purposes of this analysis and review, it is assumed that all PM_{10} consists of $\text{PM}_{2.5}$, which is the more stringent of the two standards. The most quantifiable source of PM emissions at OGS is as products of combustion from engines or other combustion producing sources. Using the conservative impacts evaluation table at the shortest distance (50 feet) and lowest dispersing stack (8 feet), for a 250 hp engines, the minimum predicted acceptable amount of emissions would be 0.9 lb/hr for $\text{PM}_{2.5}$. After a random audit of approximately 100 reviewed OGS PBR registrations in 2010, the range of PM_{10} emissions for sites was represented to be 0.01 lb/hr to 0.67 lb/hr, with an average of 0.08 lb/hr. The range of PM_{10} annual emissions for sites was represented to be 0.01 tpy to 0.57 tpy. Based on this information, it is extremely unlikely that any OGS will have or contribute to an exceedance of any PM_{10} or $\text{PM}_{2.5}$ NAAQS; therefore, a registration-specific impacts analysis is not necessary or required by this proposal.

SO_2 has several state ambient air standards, depending on location. The most stringent is a 30-minute state standard for Harris and Galveston counties of $715 \mu\text{g}/\text{m}^3$. The EPA has finalized a new hourly NAAQS of $196 \mu\text{g}/\text{m}^3$. The most quantifiable sources of SO_2 at OGS are from flares or other waste stream thermal control devices, mostly from burning sour waste streams. Using the conservative impacts evaluation table for flares at the shortest distance (50 feet), lowest dispersing stack height (20 feet), and the new proposed NAAQS ($196 \mu\text{g}/\text{m}^3$), the acceptable amount of SO_2 emissions would be 3.4 lb/hr. For that same 20 ft flare, if it is 1,400 ft away from the nearest property line, the acceptable amount of SO_2 emissions from the table would be 5.4 lb/hr. Other steady state sources of SO_2 include all combustion sources, such as engines. The average OGS has 1250 hp engines and if a typical 18 foot high stack is used, the acceptable amount of SO_2 at 1,400 ft away from the nearest property line would be 47 lb/hr.

At 2,700 feet away from the nearest property line, the amount would be 63 lb/hr; and if it is 5,500 feet away from the nearest property line, the amount would be 93.2 lb/hr. Based on a random audit of approximately 100 reviewed OGS PBR and standard permit registrations in 2010, the range of SO₂ emissions for sour sites was represented to be 15 lb/hr to 40 lb/hr, with an average of 37 lb/hr. In the same audit, the range of SO₂ emissions for sweet sites was represented to be 0.01 lb/hr to 6.30 lb/hr, with an average of 4.25 lb/hr. Although the typically highest quantity of SO₂ occurs from flares, there are other releases of SO₂ at OGS. Any sour stream going to an amine reboiler could potentially be an extremely concentrated sour gas stream and emissions from this process vent may be substantial. The dispersion characteristics of this process vent result in lower acceptable emissions as compared to a flare. Based on the impacts table for a small engine with a short eight foot stack, the smallest amount of SO₂ which meets the NAAQS at 50 feet is 2 lb/hr. Based on this information the commission would not expect a demonstration of impacts for any source to be needed at less than 2.0 lb/hr. Based on this information, most sweet sites will meet the new, more stringent NAAQS, regardless of having distances greater than 5,500 feet. For sites with emissions greater than 2 lb/hr, clear compliance demonstration with the new NAAQS cannot be determined unless further analysis is performed. In addition, it is the commission's experience that predicted concentrations do not actually occur and are not measured at the values predicted at distances greater than 5,500 feet from a source. Therefore, applicants should be required to demonstrate impacts of SO₂. Based on this information, sweet sites with great enough SO₂ emission release points and distances to receptors will most likely be able to meet the protectiveness limits of the chart; however, it cannot be concluded that most oil and gas sites would not have a problem meeting the protectiveness limits of the chart, especially sour sites. Because of this a protectiveness review is required for SO₂ to demonstrate that the site does not have or contribute to an exceedance of any SO₂ NAAQS.

H₂S has several state ambient air standards, depending on location. The most stringent is a 30-minute standard of 108 µg/m³. There are many quantifiable sources of H₂S at OGS, including fugitives, tank hatches, loading, blowdowns, and flares or other waste stream thermal control devices. Using the conservative impacts evaluation table for fugitives and vents at the shortest distance (50 feet), lowest dispersing fugitive stack height (3 feet), and the most stringent NAAQS (108 µg/m³), the acceptable amount of H₂S emissions would be 0.03 lb/hr. From the same chart, for loading at a 10 ft height, 1,400 ft away from the nearest property line, the acceptable amount of H₂S emissions from the table would be 0.5 lb/hr; for emissions from a tank hatch at 20 ft, with the tank 2,700 ft away from the nearest property line, the acceptable amount would be 1.6 lb/hr. Based on a random audit of approximately 100 of reviewed OGS PBR and standard permit registrations in 2010, the range of H₂S emissions from both sweet and sour OGS was represented to be 0.01 lb/hr to 0.62 lb/hr, with an average of 0.07 lb/hr. Based on this information, it cannot be concluded that most oil and gas sites would not have a problem meeting the protectiveness limits of the chart and a protectiveness review is required for H₂S to demonstrate that the site does not have or contribute to an exceedance of any H₂S state ambient air standard.

NO₂ is evaluated using the 1-hour NAAQS of 188 µg/m³ and the annual NAAQS of 100 µg/m³ as measured at the nearest property line to the authorized facilities. A previous compressor station study by the TCEQ showed that the NO₂/NO_x ratio appeared to max out at around 14 percent in the area downwind of the studied site where maximum NO_x concentrations were expected. Upon review of this information, the commission has determined it is reasonable to allow a lower NO₂/NO_x ratio than the national default ratio used for air dispersion modeling demonstrations. Given the submitted sampling data and previous TCEQ experience, a ratio of 20 percent is appropriate for 4 stroke engines. Several two strokes lean burn engines in the submitted data set emitted about 50 percent

NO₂ and the TCEQ believes the ratio of 50 percent is appropriate for 2 stroke engines. Using a conservative impacts evaluation for engines, the ambient ratio factor of 50 percent of NO_x is NO₂, at the shortest distance (50 feet) and lowest dispersing stack height (8 feet), the maximum predicted acceptable amount of emissions from engines smaller than 250 hp would be 3.9 lb/hr. The ratio of 50 percent is used based on analysis of NO_x to NO₂ in stack sampling discussed later in this document. Based on a random audit of approximately 100 reviewed OGS PBR and standard permit registrations in 2010, the range of NO_x emissions for sites was represented to be 0.36 lb/hr to 19 lb/hr, with an average of 4 lb/hr. Based on this information, it cannot be concluded that most oil and gas sites would not have a problem meeting the protectiveness limits of the chart and a protectiveness review is required for NO_x to demonstrate impacts of NO₂ if greater than 4 lb/hr. the site does not have or contribute to an exceedance of any NO₂ NAAQS.

Compliance with ESLs was also evaluated for possible inclusion as a requirement of OGS standard permit registrations. The maximum concentration of various speciated or groups of speciated VOCs were reviewed, including: natural gas (hourly 18,000 µg/m³), crude oil (hourly 3,500 µg/m³), condensate (hourly 3,500 µg/m³), benzene (hourly 170 µg/m³ and annual 4.5 µg/m³), toluene (hourly 640 µg/m³), ethylbenzene (hourly 2,000 µg/m³) xylene (hourly 350 µg/m³), other typical chemicals found in petroleum streams (such as propane, butane, n- iso- and cyclo-hexanes, n- iso- and cyclo-pentanes, heptanes, etc.). There are many quantifiable sources of VOCs at OGS, including fugitives, tank hatches, loading, flares or other waste stream thermal control devices, and blowdowns during planned MSS activities.

Forty-four OGS standard permit registrations were evaluated. The commission determined that only benzene requires a protectiveness review in order to demonstrate the site does not have or contribute to an exceedance of an ESL and further the commission believes that this demonstration is adequate to demonstrate protectiveness of total VOCs. The commission received many verbal and written comments that the ESL for condensate and crude oil condensate, and consequently their hourly emission limits, are not representative. The commission has derived the hourly limits from the emission parameters obtained from the oil and gas permit applications, ISC modeling and the agency published ESLs. The commission is open to revising the PBR and standard permit limits if the ESL for condensate and crude oil or any other emission limit changes in any significant manner. Written requests may be sent to Dr. Michael Honeycutt of the Commission's Toxicology Division for re-evaluation of any ESL and the commission will evaluate priorities of the Division for developing ESLs. This ESL evaluation process takes approximately one year in accordance with the procedures available at: www.tceq.state.tx.us/implementation/tox/.

The current short-term ESL of 3,500 µg/m³ was set based on the weight percent of components in typical sweet natural gas condensate. The ESL was developed by calculating each component's weight percent and its respective ESL using a formula for the derivation of a chemical product. Accordingly, an ESL of the typical sweet natural gas condensate can be derived by the following formula where f_n equals the fractional quantity of component 'n' in product X, and ESL_n equals the ESL for component 'n':

ESL for Chemical Product

$$X = \frac{1}{f_a / ESL_a + f_b / ESL_b + f_c / ESL_c + \dots + f_n / ESL_n}$$

The components and their weight percent of a typical sweet natural gas condensate are listed as follows.

<u>Component n</u>	<u>Weight percent</u>
iso-Butane	7--15
n-Butane	15--40
iso-Pentane	10--20
n-Pentane	10--20
n-Hexane	10--20
Heptane	2--10
Octane	1--5
Methylcyclopentane	1--3
Methylcyclohexane	1--3
Benzene	< 1
Toluene	0.1--1.5
Ethylbenzene	< 1
Xylene	1--3

Natural gas condensate typically consists more than 80 percent of C₄-C₈ alkanes which have low acute respiratory effects. High concentrations of these alkanes may cause temporary irritation of the nose and throat and headache, nausea, dizziness, drowsiness, anesthesia, and confusion. The short-term ESLs for alkanes are much higher than those for non-alkanes components, i.e., benzene, ethylbenzene, toluene and xylene (BTEX) in the condensate. The current short-term ESL for natural gas condensate is primarily driven by the benzene's ESLs. The acute health effects from exposure to natural gas condensate are mainly caused by the impacts of benzene. If the short-term ESLs for benzene are met, the short-term impacts for condensate emissions from OGS facilities are expected to be protective. Therefore, there is no need to conduct the short-term ESL review for condensate if benzene impacts meet their respective ESL. Further review on BTEX, and why only benzene is necessary to meet impacts is completed later in this document.

The current (interim) short-term ESL (3,500 µg/m³) for crude oil was derived based on available occupational exposure limits for similar petroleum hydrocarbons (e.g., gasoline, naphtha, and kerosene) which is conservative. The new short-term ESLs for crude oil and other similar petroleum hydrocarbons, if developed following the 2006 TCEQ Guidelines to Develop ESLs and Reference Values, may be higher approximately by a factor of 2 to 3. Therefore, a higher hourly emission rate for crude oil emissions is expected to be protective.

The commission has determined that process streams that fall in the natural gas category must contain no less than 80 percent methane and ethane. The natural gas ESL was developed with the assumption that the natural gas stream would have no more than 20 percent VOCs. All other process streams should use either condensate or crude oil for estimating overall VOCs, or the specified contaminant as describe in the impacts category.

The determination of specific contaminants which need to be reviewed was based on actual emissions; variability of actual emissions; lowest, highest, and average weight percents of each contaminant; and contribution of each speciated contaminant based on weight percents and ESLs. The following 14 speciated contaminants were addressed: benzene, butanes, cyclohexane, decane, ethylbenzene, heptane, methylcyclohexane, n-hexane, nonanes, octanes, pentanes, propane, toluene, and xylene. These 14 were chosen because they were the only speciated contaminants with more than four data points (equals a 10 percent statistical cut-off) from the 44 registrations. The chemicals which showed the highest potential culpability for impacts were benzene, toluene, xylene, ethylbenzene, cyclohexane, and methylcyclohexane.

Cyclohexane and methylcyclohexane were evaluated and determined to not be contaminants that drive the need for an impacts review. The commission determined that the conservative modeling results for these contaminants resulted in values which were higher than the actual emissions represented in the 44 registrations. Additionally, comparing the conservative modeling to the actual concentrations, the commission has seen from monitoring emissions of cyclohexane, and methylcyclohexane are not expected to cause an exceedance of ESLs. Three out of 14 data points had represented actual emissions for cyclohexane which were above the 0.32 lb/hr allowable emissions for cyclohexane at 50 feet for fugitive releases; 11 out 14 had represented actual emissions which were less than 50 percent of 0.32 lb/hr. Seven out of seven data points for methylcyclohexane had represented emissions which were below the 0.80 lb/hr allowable emissions for methylcyclohexane at 50 feet for fugitive releases.

The magnitude of some of the actual emissions, variability of emissions, and variability of weight percents of xylene, toluene, and ethylbenzene from the 44 registrations, the weighted contributions to impacts, in comparison to allowable emissions based on the impacts tables, required further review by the commission. The represented emissions for 26 of 33 data points were below the allowable emissions of 0.146 lb/hr at 50 feet for toluene fugitives. The actual represented emissions for 21 of 27 data points were below the allowable emissions of 0.08 lb/hr at 50 feet for xylene fugitives. Similar results were seen when ethylbenzene was reviewed in typical registrations. Based on this evaluation, impacts evaluations and emission limitations for xylene, toluene, and ethylbenzene were determined to not be necessary for individual registrations.

Benzene was confirmed as the main contaminant of VOC for impacts review. Thirty-four data points were obtained for benzene from the 44 registrations. In particular, the average weight percent was 3, the high-weight percent was 18, and the low-weight percent was 0.008. For at least two categories (high and average) the culpability of benzene's contribution to the impact analysis was the greatest of all contaminants evaluated. Benzene is considered a relatively toxic air contaminant, and erring on the side of caution, the commission has determined that impacts of benzene must be evaluated for distances to receptors between 50 feet and 5,500 feet. Additionally, 17 out 34 data points were represented below 0.039 lb/hr allowable emissions for fugitive releases at 50 feet, and 20 out of 34 data points were represented at or below 0.04 lb/hr, showing the potential for many sites to have negligible emissions of benzene.

Based on the commission's analysis, only benzene hourly and annual emissions need to demonstrate acceptable impacts when distances to receptors are between 50 feet and 5,500 feet, unless they are below the minimum lb/hr established in the standard permit. Speciated emissions and total VOCs emissions must be based on site specific or defined representative analysis.

Demonstration of meeting the impacts for benzene is a reasonable surrogate for a demonstration for total VOC emission limits in this standard permit. The analysis determined that if benzene can meet the impacts analysis and are protective, then all remaining VOCs should meet the impacts analysis and be protective because it has the highest combination of greatest weighted concentration and lowest ESLs of all the VOC contaminants identified for natural gas, condensate, and crude oil.

VII. ENCOURAGING RECOVERY AND OFFERING INCENTIVES

The TCEQ has numerous programs and information to encourage pollution prevention and recovery, including Clean Texas (www.tceq.state.tx.us/assistance/cleantexas/cleantexas.html) and SAV+ (www.tceq.state.tx.us/assistance/P2Recycle/site-visits.html). The EPA also has the Natural Gas STAR program (www.epa.gov/gasstar/). In addition to these resources, the TCEQ has established various industry-specific pollution prevention opportunities which include detailed, good-operating practices that help prevent pollution. Pollution Prevention through Good Operating Practices (Raw Material and Product Storage) includes the following items:

- Establishment of Spill Prevention, Control and Countermeasure (SPCC) plans
- Use of properly designated tanks and vessels only for the intended purposes
- Installation of overflow alarms for all tank and vessels
- Maintenance of physical integrity of all tanks and vessels
- Installation of leak detection systems in storage tanks
- Establishment of written procedures for all loading/unloading and transfer operations; installation secondary containment areas
- Instruction of operators to not bypass interlocks, alarms, or specifically alter set points without authorization isolation of equipment or process lines that leak or are not in service; use of seal-less pumps
- Use of bellows-seal valves
- Use of a gravity spigot or pump to reduce spills when dispensing bulk liquids
- Use of a spout and funnel when transferring liquids
- Use of drip-catchers; use of dry clean-up methods for spills whenever possible
- Documentation of all spillage to establish precautionary measures in the future
- Performance of overall materials balances and estimate the quantity and dollar value of all losses
- Use of double-seal floating-roof tanks for VOC control; use of conservation vents on fixed roof tanks
- Use of vapor recovery (vapor balance) systems
- Storage of products in locations/under conditions that will preserve their shelf life
- Maintenance of tight fitting lids and bungs on containers (even those that are empty)
- Storage of containers in such a way as to allow for visual inspection for corrosion and leaks
- Stacking containers in a way to minimize the chance of tipping, puncturing, or breaking
- Storage of packages, etc., properly to prevent damage or contamination
- Protection of items stored outdoors from temperature extremes, rain, snow, wind, severe weather
- Prevention of concrete “sweating” by raising the drum off storage pads (e.g., on pallets)
- Maintenance of Material Safety Data Sheets to ensure correct handling of spills
- Providing adequate lighting in the storage area; maintenance of a clean, even surface in transportation areas, and keeping aisles clear of obstructions
- Maintenance of distance between incompatible chemicals
- Maintenance of distance between different types of chemicals to prevent cross contamination

- Avoidance of stacking containers against process equipment
- Adherence to manufacturer's suggestions on handling and use of all materials
- Using proper insulation of electrical circuitry and inspecting regularly for corrosion and potential sparking
- Using large containers for bulk storage whenever possible
- Using containers with height-to-diameter ratio equal to one to minimize wetted area
- Emptying drums and containers thoroughly before cleaning or disposal
- Reusing and recycling scrap paper

There are numerous company (as well as environmental) benefits from implementing some or all of these ideas, including: reduced fees for select TCEQ training; technical assistance and networking; improvement in Compliance History; single point of contact within TCEQ for innovation activities; reduced state investigation frequency and additional notice on a case-by-case basis; customized recognition such as press releases, news articles, and on-site events; expedited administrative and technical review of state permits on a case-by-case basis; Exemption from source reduction and waste minimization planning requirements; reduced reporting and monitoring under discharge monitoring report provisions; stringency evaluation under air programs so sites are held to only one standard versus two; low EPA inspection priority; reduced reporting under MACT; extended hazardous waste storage time from 90 to 180 days; reduced self-inspections for certain Resource Conservation and Recovery Act (RCRA) facilities; The commission encourages all companies in the oil and gas industry to consider implementing these or any other measures which help reduce and eliminate pollution.

On February 24, 2010 the commission adopted changes to Chapter 114 to expand the Emission Reduction Incentives Grants Program of the Texas Emissions Reduction Plan. These changes include projects related to engines used for natural gas recovery. This means that if an engine can be retrofitted or replaced to reduce NO_x emissions and the engine qualifies for the program, a certain amount of reimbursement is possible based on the amount of reductions achieved. The program is applicable to 41 counties in Texas, which are nonattainment counties or affected counties.

As a part of this standard permit evaluation, the commission recognizes several opportunities for OGS to prevent emissions. The most notable may be the use of a VRS to recover, instead of a flare to destroy, VOC streams and increase saleable products. In consideration of this, the commission has included VRSs as a control option in every possible instance where a flare or thermal destruction device may previously have been the standard option for control at OGS. The commission is proposing to allow a 95 percent recovery efficiency requirement, allowing for some down time and variability of the recovery process. While this is less effective at eliminating VOCs to the atmosphere than a flare or thermal destruction device at 98 percent destruction or better, the Commission believes the resource recovery is much more important. Unfortunately, when down time of a mVRU occurs, uncontrolled emissions of crude vapors, BTEX, H₂S, etc. will occur and must be accounted for with respect to the impact analysis. For some sites with a close property boundary or close neighbors the impact potential could inhibit a company from building a mVRU for control, and might consider an IVRU instead. Ideally a company would use a VRS as the primary control for a site with a flare or thermal oxidizer as a back up as necessary. The commission wants to encourage resource recovery to the maximum extent possible, so comment is solicited for the best ways to encourage VRS use and on what the major barriers companies see to the use of VRSs.

VIII. PERMIT CONDITIONS ANALYSIS AND JUSTIFICATION

The commission has completed a comprehensive evaluation of emissions and impacts from OGS and is issuing the new standard permit to ensure these authorization mechanisms effectively regulate emissions. The standard permit applies to the specifically reviewed facilities and the operation of groups of facilities which produce, condition, process, handle and transfer petroleum liquids and gases and whose overall effects on air quality are acceptable. The standard permit authorizes OGS facilities production and MSS operations and alternative operating scenarios associated with MSS which are greater than the commission's limitations for insignificant and allows for more complex operations. However, the requirements must meet emission control and health effects guidelines, and must be below the federal major NSR permitting requirement triggers (PSD and NNSR). Any OGS which cannot meet the conditions of the standard permit may apply for a case-by-case NSR permit. The limits of the standard permit ensure protection of public health and welfare, best management practices, incentives for recovery, and practically enforceable recordkeeping.

The following discussion describes the new standard permit.

Paragraph (a) outlines the applicability of registrations under this new standard permit. The paragraph covers new or changed facilities (units, equipment), groups of facilities (compressor/engine/fugitive components and piping), and sites (plants/property-wide) which may use this authorization. This authorization may be used to cover several categories: new (green field) OGS; additions of facilities or groups to existing authorized sites; and changes to existing, authorized facilities, groups, or sites handling or processing petroleum liquids and gases. Based on comments received from stakeholders, both sweet and sour operations are able to use this standard permit.

The majority of the standard permit requirements are only applicable to new facilities or modifications that increase emissions at existing standard permit facilities. Administrative agencies, like TCEQ, exercise power delegated to it by the Texas Legislature. It is established that statutes passed by the Texas Legislature are presumed to have prospective effect only (TEX. CONST. ART I § 16 (prohibiting bills of attainder, *ex post facto* laws related to penal or criminal penalties, retroactive laws, or any statute that impairs the obligations of contracts); TEX. GOV'T CODE ANN. § 311.022 (stating statutes are prospective unless expressly made retroactive)). Thus, when the legislature grants rulemaking authority to an agency, this same presumption applies. The policy behind the presumption is that retroactive application of statutes and rules does not provide fair notice and the public cannot reasonably rely on the current regulations. Therefore, the standard permit will not be applied retroactively, but will be applied to those facilities that are either newly constructed or modified.

The commission has modified paragraph (a) to include the requirements for the applicability dates for the Barnett Shale. The commission, like all state agencies, is faced with helping resolve substantial budget deficits and has limited resources. Therefore, the commission has chosen to narrow the scope of the application of this rule package to ensure it has the ability to implement this rule in an efficient and effective manner. The commission determined that the rule should apply to the area of the state with the greatest number of wells located in close proximity to the greatest number of residents. Therefore, the commission has included subsection (a)(1) which provides that 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) will be subject to subsections (a) - (k) on or after April 1, 2011.

The Barnett Shale area has been chosen because it presents the greatest challenge to the commission due to the high volume of current drilling sites and its close proximity to dense urban populations. The implementation of the rule in the Barnett Shale area only will give the commission an opportunity to evaluate its administration of the new rule in the area that presents the greatest administrative challenge. By demonstrating that the commission can apply the rule in an efficient and effective manner in the Barnett Shale area, the commission can further evaluate the benefits of state-wide application. For all other new projects and related facilities outside the Barnett Shale, only subsection (1) will be applicable.

Paragraph (a)(2) requires that all oil and gas facilities be authorized under one Oil and Gas standard permit to ensure a single appropriate authorization for related facilities and protectiveness of all similar emissions. To ensure that site-wide authorizations are used at an OGS, facilities requiring authorization by a case-by-case permit cannot use this standard permit for new facilities or make changes to existing facilities. Finally, this paragraph does continue to allow other facilities which are not changing to remain authorized under historical standard exemptions or permits by rule as long as their emission contribution is evaluated for protectiveness.

Paragraph (a)(3) requires owners and operators to comply with all applicable provisions of the THSC, Texas Water Code, the rules of the commission, and any other applicable federal, state, or local regulation. If emissions from the OGS exceed the limitations of the standard permit, the site cannot be authorized.

Paragraph (a)(4) prohibits the use of this standard permit to authorize upsets, emergencies, or malfunctions. The commission believes these types of activities and releases are not appropriate to be authorized in any circumstance, and instead should be covered under 30 TAC §101.201, Emissions Event Reporting and Recordkeeping Requirements. Based on stakeholder comments, the commission has also included the clarification that this standard permit does not regulate methane, ethane, or carbon dioxide. If the federal or state government promulgates requirements for these air pollutants, separate rules and requirements will have to be met following paragraph (a)(3).

The commission's intent in adopting this new standard permit is to ensure that new OGS or changes to existing sites appropriately focus on protection of public health and welfare, BMPs, incentives for recovery, and practically enforceable recordkeeping. Reviews under updated technical requirements will ensure facilities authorized by the commission will meet state and federal air quality standards and guidelines based on an evaluation of all potential emissions.

Paragraph (b) describes the scope of the standard permit and defines the terms which are critical to ensuring the understanding or, and consistency with the expected uses of this standard permit, including federal permit applicability, registration, and protectiveness review and emission limitations.

The definition of facility is adopted in paragraph (b)(1) for clarity, and does not change any of the commission's other rules on the definition of facility. This term is included since there are frequent misunderstandings regarding the use of the term "facility". Many customers and the general public use the word "facility" to describe entire plants or groups of equipment, not each individual source of emissions. THSC §382.003(6) specifically excludes well tests from the definition of facility. State law further narrows the exception in THSC, §382.003(13) and limits the well testing time to 72 hours.

Paragraph (b)(2) defines receptor for the purpose of determining the most appropriate emission limit which is based on the distance to the defined receptor. For the air contaminants with potential health effects, distance measurements will be taken from the source of the emissions to the nearest off-property receptor. Receptor has been defined to include structures which are in use as a single or multi-family residence, school, day care, hospital, or place of worship at the time this standard permit is claimed. In response to comments, the definition of receptor has been expanded to include certain businesses. These receptors are included if they are occupied regularly as those in the general public who occupy these structure may be exposed for extended periods of time. The business definition however excludes those businesses whose primary function is oil and gas production, as the emissions they are exposed to are the same – and in much higher concentrations- as the site seeking authorization may be emitting. The reason for including the phrase "at the time this standard permit is claimed" is to provide certainty as to evaluating what is considered a receptor at the time this standard permit is claimed.

Residence is defined for this standard permit as a structure primarily used as a permanent dwelling. The term residence is used throughout various statutes and rules of the TCEQ and other state agencies. However, the term is not defined under the Texas Clean Air Act (TCAA) or by air quality-related agency rules. Webster's II New College Dictionary, 1995, defines "reside" as "to live in a place for a permanent or extended time." It further defines "residence" as "the place in which one lives." Texas courts have generally accepted that "residence" means "the place where one actually lives or has his or her home; a person's dwelling place or place of habitation; a dwelling house" (Owens Corning v. Carter, 997 S.W.2d 560 (Tex. 1999); Malnar v. Mechell, 91 S.W.3d 924 (Tex. App. Amarillo 2002); Dickey v. McComb Development Co., Inc. 115 S.W. 3d 42 (Tex. App. San Antonio 2003)).

In most situations it is generally self-evident whether or not a structure is a residence. In some cases questions may arise as to the type of a structure, and if it should be considered a receptor, located near a facility when determining its compliance with applicable distance requirements. If necessary, a determination shall be made by the TCEQ commission regarding whether or not a structure is a residence. The commission may consider factors and circumstances specific to the situation when making the determination. Potential factors that may be considered include, but are not limited to, local tax rolls showing the property as a residence, utility bills showing a residential rate, location of structure in a neighborhood with any deed restrictions or zoning ordinances on use as a business or other non-residential activity, or the frequency of the use of the structure as a residence.

The receptor definition for this standard permit does not include structures occupied or used solely by the owner or operator of the OGS facility or the owner of the property upon which the OGS facility is located if they have a mineral rights interest in the OGS. In Texas, there are rights granted to mineral owners and rights granted to surface owners, but these rights are not always held by the same person. To get to their mineral property, mineral owners typically, coordinate with surface owners.

The standard permit states that all measurements from emission sources to receptors shall be taken from the project location, which requires registration under the standard permit, to the nearest receptor. The locations listed above are considered to be areas where the general public may congregate or be exposed to emissions for extended periods of time, and the standard permit will ensure no negative effects occur at receptors.

The definition of receptor and language are consistent with the current air quality standard permit for permanent rock and concrete crushers with certain additions. The original language is from House Bill 2912, 77th Legislative Session, 2001. The law was codified in the statute under THSC §382.065, and addressed concrete crushers only. The law specifically used the language "single or multifamily residence, school, or place of worship" to refer to receptors. However, the commission has chosen to include not only single or multi-family residences but, day cares and hospitals in its definition of receptor because the inhabitants of these structures are typically more susceptible to the effects of air emissions from pollutants of concern regulated by this standard permit. In response to comments, the definition of receptor has been expanded to include certain businesses. These receptors are included if they are occupied regularly as those in the general public who occupy these structures may be exposed for extended periods of time. The business definition however excludes those businesses whose primary function is oil and gas production, as the emissions they are exposed to are the same – and in much higher concentrations- as the site seeking authorization may be emitting. The reason for including the phrase "at the time this standard permit is claimed" is to provide certainty as to evaluating what is considered a receptor at the time this standard permit is claimed.

Paragraph (b)(3) defines OGS as it pertains to this standard permit. Paragraph (b)(3) highlights the critical parameters established by the commission and EPA, for the purposes of the determining major sources under the federal operating permits program. Following comments received from EPA as a result of the stakeholders meeting, the commission has included the required reference of standard industrial classification (SIC) codes, facilities under common control of the same person (or persons under common control), and located on contiguous or adjacent properties. The commission has revised this definition in order to be more consistent with the definition in Chapter 122. In no way do the provisions of this paragraph allow owners or operators to avoid federal aggregation regulations, if those regulations and policies are applicable. Specifically, an owner or operator may not apply the provisions of this paragraph until it has been confirmed that the site does not trigger PSD or NNSR applicability.

The federal operating permit definition of OGS is included in paragraph (b)(4) for emphasis, and does not change any of the commission's other rules on the definition of site. It is complicated to define an OGS precisely given the diverse nature of OGS activities where the well sites can cover several square miles and can be located hundreds of miles from the actual OGS processing plants. Further complicating the definition of an OGS is land ownership, subsurface mineral rights, surface property rights, lease agreements, and site control, which are not easily distinguished in this industry. There are many considerations and memorandums issued on this subject available through the following: www.epa.gov/ttn/oarpg/. The commission also publishes a guidance document which outlines the state's expectations for reviews (http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/Title_V/site.pdf), and due to the major source potential of OGS, this standard permit incorporates the limitations outlined in that document.

Paragraph (b)(5) highlights the limits and scope for state authorization purposes and defines a project under this standard permit as meeting all requirements of this standard permit prior to construction or implementation of changes. These new or changing facilities must be operationally dependent to existing, unchanging oil and gas facilities as referenced in paragraph (b)(5)(A). In the past, no clear definition of project had been provided. In response, the commission has revised the standard permit and defined "project" consistent with other NSR permitting actions. The commission has also revised the scope of "registration" and established a fixed boundary in order to provide certainty to the regulated community and the public of which facilities are included in the registration.

Registration, and all applicable requirements, under this standard permit are triggered when a physical or operational change to existing authorized facilities or group of facilities will increase the potential to emit over previously certified emissions limits as referenced in paragraph (b)(5)(B) or (b)(5)(C). It is imperative for companies to address previously registered emissions limitations in order ensure that any change with a potential to increase emissions at an existing site will not trigger the new standard permit requirements (see 30 TAC §116.615).

Paragraph (b)(6) specifies the scope of a registration. As with the major source determination, all OGS facilities should be included. Under this standard permit, the facilities which are covered under a single standard permit registration must be located no more than ¼ mile apart and should be operationally dependent as listed in paragraph (b)(6)(A). The commission considers that combinations of facilities and equipment, which are constructed and operated together to handle materials or make a product to be related, and require a single authorization. Based on stakeholders' comments, the distance measurement is limited to a radius of no more than a 1/4 mile from the new facilities or groups facilities that have the potential of increasing emissions as listed in paragraph (b)(6)(B) through (b)(6)(E). This distance is limited by excluding piping, fugitive components, and other similar facilities for transmission of natural gas or crude oil because OGS are often required to have isolation valves or cutoffs (fugitive components) for safety reasons by other state and federal agencies. Finally, to ensure a complete evaluation within the established boundaries, fugitive emission releases must be included for purposes of emission limits.

As a result of the site-wide emission limits, if piping or fugitive components are the only connection between facilities, and there is a ¼ mile distance between the facilities, then the facilities are considered separate when determining the ¼ mile separation for registration as listed in subparagraph (b)(6)(C). Additionally, the boundaries of the registration become fixed at the time this standard permit is claimed and registered. No individual facility may be authorized under more than one registration as listed in subparagraph (b)(6)(D). This requirement will ensure that there will be no boundary creep or daisy-chaining as modifications occur at the site, thus giving certainty to compliance demonstrations. Any facility or groups of facilities authorized under an existing standard permit registration, which is operationally dependent on a project, must be revised to incorporate the project as listed in paragraph (b)(6)(E). A registration may include facilities which are claiming historical standard exemptions and PBRs, as well as projects that will be claimed under this standard permit. Existing authorized facilities, or groups of facilities, at an OGS under this standard permit, which are not changing the certified character or quantity of emissions, must only meet the protectiveness review and planned MSS requirements of this standard permit as listed in paragraph (b)(6)(F). Unique to standard permits, all facilities which are related are required to meet all requirements of the standard permit at renewal. The commission has established a reasonable future date of January 1, 2016 after which all renewed standard permit registrations must meet all requirements, including protectiveness, BMP, and BACT.

Paragraph (b)(7) addresses planned MSS at OGS facilities. In 30 TAC §101.222, Demonstrations, there is a clear expectation and mechanism to authorize planned MSS, with a specific schedule depending on SIC code. Although the oil and gas industry's scheduled date is not until January 5, 2012, the standard permit relies on an assessment and evaluation of anticipated MSS activities. It is under these requirements and limits that MSS is authorized since no previous version of the OGS standard permit clearly reviewed these emissions. However, since the previous standard permit requirements did require an impacts review under 106.261-262, emissions which have been registered and reviewed are protective. For any new registrations, or for new planned MSS for existing authorizations, the commission is requiring that these emissions demonstrate compliance with the protectiveness review.

It should also be noted that MSS is not currently required to be authorized nor will sites lose their existing affirmative defense opportunities until January 5, 2012. Adding the MSS annual emission release quantities to production releases, and confirming that all requirements of a standard permit continue to be met, this evaluation for all new and existing sites also ensures that federal operating permit applicability for traditional criteria air contaminants is assessed in accordance with EPA and TCEQ rules and policies.

The authorization of planned MSS associated with existing OGS does not by itself require a notification or registration. The commission requires records to be kept on site and made available upon request

Paragraph (b)(8) addresses the obligation of permit holders to ensure the protection of public health and welfare, and demonstrate compliance with applicable ambient air standards. Paragraph (k) requires companies to demonstrate protectiveness based on an assessment of peak and cumulative emissions which will not cause, or contribute to, air pollution in excess of any maximum allowable increase or maximum allowable concentration for any pollutant in any area to which this standard permit applies, national ambient air quality standard in any air quality control region, or any other applicable emission standard or standard of performance under Chapter 106.

Having annual and short-term protective emission limits from all types of activities and operations on a site-wide basis meets the fundamental criteria for insignificance in the hierarchy of air quality authorizations and the fundamental intent of the TCAA. Hourly emission limits are necessary in order to ensure protection of public health from short term exposure. Hourly emission limits are a necessary part of this standard permit since both ambient standards and ESL guidelines exist on a hourly basis, therefore a direct confirmation is the most appropriate and practically enforceable standard permit requirement.

Paragraph (b)(8)(A) identifies the scope of the protectiveness review. To ensure all similar emission sources under common control on a contiguous property in close proximity are evaluated, the standard permit requires an impact analysis be done on a contaminant-by-contaminant basis for any net project emission increases. To ensure only appropriate review, if a claim under this standard permit is only for planned MSS, the analysis only needs to evaluate planned MSS. The outcome of the protectiveness evaluation may establish more stringent limits than otherwise required by the standard permit, and will ensure that property lines and receptors in close proximity to the OGS have been evaluated.

Paragraph (b)(8)(B) establishes limits on hourly and annual emissions based on the most stringent of paragraphs (h) or (k) of this standard permit. There are numerous state and National Ambient Air Quality Standards (NAAQS) applicable to the emissions associated with an OGS, including NO₂ (hourly 188 micrograms per cubic meter (µg/m³), annual NAAQS, 100 µg/m³); CO (hourly NAAQS 40,000 µg/m³ and 8-hour NAAQS 10,000 µg/m³), sulfur dioxide (SO₂) (new hourly NAAQS 196 µg/m³, 3-hour NAAQS 1300 µg/m³, 24-hour NAAQS 365 µg/m³, and annual NAAQS 80 µg/m³, most stringent state 30-minute standard 715 µg/m³), particulate matter (PM) less than or equal to ten microns in diameter (PM₁₀) (24-hour NAAQS 150 µg/m³, PM less than or equal to 2.5 microns in diameter (PM_{2.5}) (24-hour NAAQS 35 µg/m³, annual NAAQS 15 µg/m³). H₂S does not have a NAAQS, but is regulated by 30 TAC Chapter 112, Control of Air Pollution from Sulfur Compounds (statewide standard is 162 µg/m³, with the most stringent state standard at 108 µg/m³). Also present at OGS are contaminants that include, but are not limited to, natural gas, condensate, crude oil, benzene, and other common contaminants.

These contaminants must meet their respective effects screening levels (ESLs) as shown at: www.tceq.state.tx.us/implementation/tox/esl/list_main.html. Specific compliance demonstrations of certain air contaminants are not required for any individual registration based on an analysis of the protectiveness review and a large number of OGS registrations recently reviewed by the commission.

Paragraph (c) establishes the expectations for authorizations of new facilities, changes to existing facilities which increase emissions, and newly authorized activities of facilities which result in emissions. Paragraph (c)(1) covers existing OGS which are authorized under previous versions of the OGS standard permit and the changes which may occur at those locations. Paragraph (c)(2) covers registration requirements for all new registrations or updates to existing registrations. Paragraph (c)(3) establishes that the reasons for which the commission may deny a registration.

Paragraph(c)(1) covers various possible changes at existing OGS. Subparagraph (c)(1)(A) covers situations where new facilities are added to an OGS, registration of those facilities is required following paragraph (b)(5). When changes occur to existing facilities which increase their potential to emit, or increase emissions above previously certified emission limits, registration of those facilities is required following paragraph (b)(5). In both of these circumstances, the new and changing facilities must be evaluated under all portions of the standard permit. At those same sites, other facilities which are not affected by the new or changing facilities are not required to meet the requirements of the standard permit. However, existing unchanged facilities must be included in the site-wide protectiveness evaluation.

Paragraph (c)(1)(B) covers very small possible changes at existing OGS and establishes appropriate minimal requirements and waives full registration and review. Common changes at OGS include updating and adding standard permits of piping, associated fugitive components, and small equipment additions. Additionally, small engines (up to 100 hp) are often added to supplement other equipment operations. These types of changes are inconsequential when considering all other potential and actual emission sources at an OGS. These types of changes are also commonly made, and placing registration, notification, or other prescriptive requirements is burdensome and unnecessary in the commission's opinion. The negligible increases adopted by the commission would be limited to emissions less than or equal to 1.0 tpy VOC, 5 tpy NO_x, 0.01 tpy benzene, and 0.05 tpy H₂S. These values were established well below any applicable threshold and should not contribute to any impact evaluation exceedances. These increases are also limited to a rolling 12-month period because the commission does not want to authorize perpetual changes at an OGS without agency review or compliance demonstrations. To ensure proper operation and accurate accounting, these negligible changes and additions would be required to follow BMPs, keep records over a rolling 60-month period, and not result in changes at other facilities at the site or increase the OGS potential to emit air contaminants. Keeping records over a rolling 60-month period is the same duration as Title V permit recordkeeping requirements. Title V permit recordkeeping requires the longest or same duration of recordkeeping in comparison to other state of Texas and federal rules. Keeping records over a rolling 60-month period ensures compliance and practical enforceability. Negligible changes still need to comply with technical requirements after recordkeeping is no longer required. Negligible changes are not counted toward registration requirements after recordkeeping is no longer required. Negligible changes must still be incorporated into the next revision or certification of a registration.

Paragraph (c)(1)(B)(v) covers like-kind replacement of existing facilities under very specific circumstances. If all requirements are met, the entire OGS does not need to undergo a full review since under these limited circumstances it is not appropriate or necessary for protectiveness of continuing OGS operations. The first criteria are that the new replacement facility must have the same or less emissions than the facility being replaced. Next, there can be no other effect on the OGS's emissions. The replacement facility cannot trigger any federal NSR review requirements and must comply with any applicable state or federal standard. Finally, the replacement facility must be incorporated into the registration or file at the next revision or renewal. With these options at existing authorized OGS, the industry is given flexibility to be responsive to resolve equipment problems before failures and upsets occur and the commission is minimizing unnecessary paperwork and resources for non-substantial changes. Additionally, replaced facilities cannot exceed major source or major modification thresholds as explained in paragraph (c)(2)(A).

Paragraph (c)(1)(C) has also been included to provide operational flexibility, which ensuring small changes at a standard permit site remain protective. This paragraph allows new facilities or changes which otherwise meet PBRs 30 TAC §106.261-262 if those projects also demonstrate emissions meet the review required in paragraph (k).

Paragraph (c)(2) establishes expectations for all registrations and authorizations under this standard permit and reminds all permit holders that this standard permit does not authorize any major sources or major modifications. In addition, any facility or activity which also is subject to a federal New Source Performance Standards (NSPS), National Emissions Standards for Hazardous Air Pollutants (NESHAP), or Maximum Achievable Control Standards (MACT) must meet those requirements, regardless of the requirements of this standard permit. Finally, all facilities and activities must also comply with any applicable state regulation as stated in Paragraph (c)(2)(C).

Subsection (c)(3) has been revised so that the grounds for denying a PBR have been replaced with additional requirements an applicant must meet in order to qualify for this PBR. The revised language states that to be eligible for this PBR, an applicant: shall meet the requirements of the PBR; shall not misrepresent or fail to disclose fully all relevant facts in obtaining the permit; and shall not be indebted to the state for fees, payment of penalties, or taxes imposed by the statutes or rules within the commission's jurisdiction.

Paragraph (c)(4) recognizes that historic stacking of SE, PBRs and standard permit authorizations have been used in various configurations over time as groups of facilities change or expand. This paragraph outlines the fact that these facilities will not retain their original authorization, but become authorized by the standard permit. However, most of the technical requirements under which these facilities will continue to operate, if they are not physically or operationally changed in a way as to increase emissions, will be that of their historical authorization. These facilities would be expected to meet BMP, records and monitoring requirements. The commission believes this to be a reasonable compromise to consolidate all dependent facilities into a single authorization, without unnecessarily requiring retroactive control requirements on unchanged facilities.

Paragraph (d) establishes which facilities are authorized under this standard permit. Paragraph (d)(1) specifically lists all facilities and sources considered in this evaluation. In accordance with comments from EPA, any standardized authorization mechanism must be unit-specific and not allow any uncertainty or unforeseen facility authorization.

The commission has evaluated numerous facilities, along with supporting infrastructure equipment for this standard permit, including: fugitive components, including valves, pipe flanges and connectors, seals, instrumentation, and associated piping; pumps and meters; separators, including gun barrels, free-water knockouts, oil/water, and membrane units; condensers for process operations; treatment and processing, including heater-treaters, methanol injection, glycol dehydrators, molecular or mole sieves, amine sweeteners, H₂S scavenger chemical reaction vessels for sulfur removal, and iron sponge units; cooling towers; gas recovery units, including cryogenic expansion, absorption, adsorption, heat exchangers and refrigeration units; combustion units, including engines, turbines, boilers, reboilers, heaters and heater-treaters; storage tanks for crude oil, condensate, produced water, pressure tanks with liquid petroleum liquids, fuels, treatment chemicals, and slop and sump oils; surface support facilities associated with underground storage of gas or liquids; truck loading equipment (except for vacuum truck loading equipment); control or recovery equipment including vapor recovery systems, condensers for control or recovery, flares, vapor combustors, and thermal oxidizers; and temporary facilities used for planned maintenance, and temporary control devices for planned startup startups and shutdowns (except for planned MSS degassing operations).

Paragraph (d)(2) also lists the types of facilities and operations that are not authorized by this standard permit. Several units and operations were excluded for various reasons for consideration under the standard permit. Paragraph (d)(2)(A) discusses sulfur recovery units (SRU) which are not authorized because it was discovered that when an SRU was pulled out of service for maintenance, the emissions typically exceed PSD applicability significance levels. This represents a major source as defined in 30 TAC §116.12, Nonattainment and Prevention of Significant Deterioration Review Definitions, which cannot be authorized by a standard permit as referenced in (c)(2)(A). The only way to prevent triggering federal PSD requirements is to maintain a second SRU to switch over during maintenance operations. Since the review of permitted OGS did not reveal any dual SRUs, the commission concluded that the industry was reluctant to invest in the capital outlay, and consequently SRUs were excluded from the evaluation. Sour water strippers, which are used to remove H₂S from water, were not evaluated for protectiveness since they are associated with SRUs. In paragraph (d)(2)(B), carbon dioxide hot carbonate processing units were excluded since the commission was not able to obtain sufficient processing and emission data for production, or MSS emissions on these units from applications it reviewed. As a result the commission was not able to evaluate these units. The commission requested comments on carbon dioxide hot carbonate processing units, but received no information from commenter's and therefore adopts new (d)(2)(B) to exclude these units.

The commission adopts paragraph (d)(2)(C) to exclude water injection facilities from authorization under this standard permit. These are subsurface facilities involved in waste disposal activities, which are beyond the scope of the OGS production processes at the sites evaluated. Instead, many of these facilities and operations can claim PBR, §106.351. Transfer of liquefied petroleum gases, crude oil, or condensate by railcar, or marine barges was also excluded in paragraph (d)(2)(D) as these operations were not found at sites in the commission's review because larger OGS use pipeline transfer for economic and geographical reasons. However, if these operations occur on a small scale, other PBRs may be claimed, such as by §106.261 and §106.262. Paragraph (d)(2)(E) excludes solid waste incinerators because they were rarely found in evaluations of existing authorized PBR and standard permits. The resources required for a comprehensive evaluation of potential emissions, control specifications, and impacts were determined to be unnecessary as a part of this proposal. In paragraph (d)(2)(F), remediation of water and soil as a result of petroleum spills is excluded. These activities can be independently authorized under §106.533, Remediation, and in some cases, are covered by the Texas Railroad Commission regulations.

Paragraph (d)(2)(G) excludes direct contact cooling towers or heat exchangers to ensure that VOC and other air contaminants are not stripped from waste or product streams and inadvertently emitted to the atmosphere. Additionally, the commission has determined that direct contact cooling towers or heat exchangers is not good engineering practice for OGS. In response to comments, subsection (d)(2)(H) which was proposed to prohibit the use of the standard permit in an Air Pollutant Watch List (APWL) area for any applicable APWL contaminants for that area has been deleted. The commission agrees that isolating the oil and gas industry is inappropriate at this time and the need to more strictly control air pollutants in these areas justifies changes to the general requirements for all standard permits. The current practice to closely evaluate any increases of pollutants of concern in APWL designated areas will continue, and continuing to pursue this policy and practice will help ensure that standard permit authorizations will not contribute to existing, monitored problems in specified areas of the state.

Paragraph (e) addresses that any new facility, group of new facilities, or changes to existing facilities which increase the potential to emit or any increase in emissions over previously certified representations, and any associated emission control equipment at OGS under the standard permit needs to meet Best Management Practices (BMPs) and best available control technology (BACT) requirements. The commission adopts paragraph (e) to require BMPs and minimum BACT requirements for new and changed facilities at an OGS authorized under this standard permit. These requirements are not applicable to existing, unchanged facilities at an OGS. For new and changing facilities, design and operation requirements are needed to prevent emissions from being generated or escaping from these sources.

To emphasize the importance of BMP, the commission adopts paragraph (e)(1) to reiterate the regulatory requirements from §101.221, Operational Requirements, for keeping all facilities' capture, recovery, and control equipment in good working order. This is essential to ensure that facilities are meeting authorization limits. Additionally, the commission proposes that paragraph (e)(1) to require sites to establish a program for replacements, repairs, and maintenance on facilities for those chosen by the operator to meet the limitation of this standard permit. The commission adopts paragraph (e)(1) as initially proposed. The commission proposes paragraph (e)(1)(A) for addressing compliance with manufacturer's specification and recommended programs applicable to equipment performance and effect on emissions as listed in paragraph (e)(1)(A) has been added to ensure that equipment is operated as intended. The commission adopts (e)(1)(A) as initially proposed and adds the words *compliance with* at the beginning of (e)(1)(A) to provide clarity of meaning in response to comments. The commission proposes cleaning and routine inspection in paragraph (e)(1)(B) to ensure ensures that equipment is not left to operate endlessly without necessary routine attention. However, cleaning does not include degassing, which is separately addressed in the standard permit. The commission adopts paragraph (e)(1)(B) as initially proposed and adds the word routine in front of inspection for clarity. The commission proposes paragraph (e)(1)(C) for replacement and repair of equipment on schedules which prevent equipment failures and maintain performance are listed in paragraph (e)(1)(C). This is to ensure that when replacement and repair of equipment is necessary, it is done at an interval both consistent with manufacturer's recommendations and at a time of the operators choosing. The commission adopts paragraph (e)(1)(C) as initially proposed. The commission has determined that replacements, repairs, and maintenance of equipment are good engineering practice and necessary to ensure minimization of emission releases.

The commission deletes the initially proposed language in paragraph (e)(2) and instead moves the initially proposed language from paragraph (e)(3) to (e)(2). The commission adopts paragraph (e)(2) that requires OGS facilities to be operated at least 50 feet from any property line or receptor (whichever is closer to the facility).

Fifty feet is the limit of the modeled impacts, and should provide a reasonable buffer considering the potential location of many OGS throughout Texas. In the rare circumstance of a receptor on the site itself, 50 feet from the receptor to the nearest facility would still be needed. Furthermore, The commission adopts paragraph (e)(3)(A) as initially proposed and changes paragraph (e)(3)(A) to paragraph (e)(2)(A). Paragraph (e)(2)(A) requires that any valve that is for isolation and for safety purposes can only consist of fugitive components, and must meet the separation requirements of at least ½ the distance of any applicable easement as defined by federal requirements (49 CFR Part 195.210 and 195.248), guidance set forth by the Texas Railroad Commission, or local entities. The commission adopts paragraph (e)(2)(B) to exempt from the 50 feet distance requirement any properly authorized existing facility, even if modified. The commission adopts paragraph (e)(2)(C) to waive the distance limitation for existing OGS 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 standard permit. The language under paragraph (e)(2)(C) is essentially as previously proposed with different wording used in response to comments to provide more clarity. In response to comments, the commission added language to paragraph (e)(2)(C) to encourage moving facilities to meet the 50 foot requirement. In response to comments, the commission added language to paragraph (e)(2)(C) to indicate replacement facilities must meet all other requirements of the OGS standard permit; the commission does not consider replacement of facilities as maintenance as was claimed in comments. The commission determines that replacement facilities are new facilities. Existing OGS facilities which are located less than 50 feet from a property line or receptor when constructed and previously authorized would be exempt from this distance limitation even if they are modified, unless good engineering practice would permit, since it is unfeasible to move these facilities. The commission has also clarified that this distance is not applicable if a receptor is subsequently built within this buffer zone.

The commission moves proposed paragraph (e)(4) to paragraph (e)(3). Paragraph (e)(3) addresses engines and turbines. The commission determines that, although not specifically stated in the OGS standard permit, to eliminate confusion over when an OGS must register or notify the commission for engines and turbines and to account for engine and turbine requirements that are not accounted for in §106.512, the standard permit language does not allow the previous outdated requirement of §106.512 to be used. The commission determines that instead, new or modified engines and turbines under the standard permit must meet specific NO_x, VOC and CO requirements. These requirements criteria are based on Tier I BACT determinations, current Chapter 117, Control of Air Pollution from Nitrogen Compounds, requirements and federal NSPS. The commission determines that some existing engines must meet specific NO_x requirements by specified phase-in dates. The commission proposed subparagraph (e)(4)(A) to require engines and turbines to meet the emission and performance standards listed in Table 6 in paragraph (l). The commission changes Table 9 to Table 6 and changes paragraph (l) to paragraph (m). The commission adopts Table 6, “Engine and Turbine Emission Operational Standards” due to renumbering and to place the table next to the engine modeling table.

In response to comments, the commission adopts a fourth engine type, dual-fuel, and requires that it meet the standards for 4-stroke lean burn engines because of the similarity in operation and control options for both types of engines. Also the commission adopts a clarification that the rich and lean burn engine standards apply to only non-emergency, spark-ignited rich and lean burn engines. The manufacture date is the date of original manufacture unless reconstructed as defined by NSPS regulations in which case the reconstruction date becomes the manufacture date.

Since many older engines may not be able to be modified to reduce NO_x emissions to the specified levels without significant reconstruction, the commission is adopting certain specific criteria which allows these older engines to be replaced or retrofitted with controls over a reasonable period of time (no later than January 1, 2015, for rich burn engines and no later than January 1, 2020 for lean burn engines). NO_x emission limits prior to those dates are based on the existing requirements of §106.512 and the newly promulgated NSPS standards for spark-ignited stationary engines. Any rich burn engine less than 100 hp does not have an applicable standard under the standard permit because these engines typically are not controlled. Two-stroke lean-burn engines less than 500 hp do not have an emission standard because they typically are used in specialized service and are insignificant as a class.

The commission proposed rich burn engine standards that apply to engines greater than 100 horsepower (hp). The standard permit requires BACT to be applied to all facilities. Engines under 500 hp have emission standards applicable and an analysis has shown replacement or upgrades of these units are reasonable. Rich burn engines greater than 500 hp have until 2020 to modify existing catalyst trains if necessary to meet this standard permit. This is the only additional control cost that has been imposed on the industry for rich or lean burn engines in this standard permit. Costs are expected to be minimal due to the schedule in Table 6 which allows current maintenance plans to incorporate the potential need for enhanced control. In response to one comment, the commission adopts a clarification that the standard for rich burn engines manufactured after January 1, 2011 applies to engines manufactured on or after the date. Emission limitations are also established for CO and VOC emissions from engines and CO emissions from turbines, representing reasonable control while allowing for retrofits for NO_x control. The commission proposes a VOC standard for rich burn engines greater than 100 hp and manufactured before January 1, 2011. In response to comments, the commission adopts no VOC standard for these engines. The commission believes CO is an adequate surrogate for VOC and that the initial sampling for CO combined with quarterly monitoring for CO at sites with larger potential to emit is appropriate. The additional cost of monitoring for VOC has been eliminated but registrations still must contain appropriate estimates of emissions.

The commission also adopts in subparagraph (e)(3)(A) that diesel fueled engines can be used for back-up power generation and periodic power needs at OGS if the fuel has no more than 0.05 percent sulfur and is operated less than 500 hours per rolling 12-month period. The commission deletes the sweet gas or liquids language from subparagraph (e)(4)(C) in response to comments. The commission determines that limiting use to sweet gas or liquids is unnecessary and arbitrary limit and that it is not in the best interest of OGS to use sour gas or liquids that would damage combustion units. In response to comments, the commission changes diesel fueled to liquid fueled. The commission determines that limiting the liquid fuel type to only diesel is an unnecessary and arbitrary limit. The commission adopts subparagraph (e)(3)(B) to allow the use of engines and turbines for more than 876 hours per rolling 12-month period for electric generation if no electric grid access is available and if the turbines and engines meet Table 9 (changed to Table 6) standards for engines and turbines, or else, electric generators must meet only the technical requirements of the Air Quality Standard Permit for Electric Generating Units. The commission changes the language in (e)(3)(B) from no electric grid access to no reliable electric grid access in response to comments. The commission agrees that an available electric grid may not be able to handle the additional electricity load for OGS without significant upgrading of the electric grid itself. The commission added language to clearly indicate that the emissions from EGUs need to be included under OGS registration (not the EGU standard permit.) The commission moves subparagraph (e)(4)(D) to subparagraph (e)(3)(B).

Finally, the commission proposes subparagraphs (e)(4)(E) and (e)(4)(F) to require that engines and turbines meet all the requirements of Chapter 117 and all applicable requirements of relevant NSPS and MACT standards, respectively. This paragraph requires operators to follow the more stringent or additional requirements, regardless of this standard permit. These requirements include Chapter 117 and various NSPS and MACT standards (additional details can be found in the Air Quality Standard Permit for Oil and Gas Sites technical summary). The commission adopts subparagraphs (e)(4)(E) and (e)(4)(F) as initially proposed. The commission moves subparagraphs (e)(4)(E) to (e)(4)(F) to subparagraphs (e)(3)(C) and (e)(3)(D), respectively. The commission also adds and adopts subparagraph (e)(3)(E) for allowing compression ignition engines rated less than 225 kW (300 hp) provided that emissions are less than or equal to the emission tier for an equivalent sized model year 2008 non-road compression ignition engine under 40 CFR§ 89.112, Table 1. The commission determines that, in general, the use of such compression ignition engines is acceptable at OGS. Additionally, the commission notes in only the preamble that the standard permit does not authorize engines used for drilling purposes. The commission does not have regulatory authority over drilling operations. Additionally, in almost every instance, engines used for drilling purposes do not remain on the site for 12 consecutive months, and therefore, are not considered stationary sources needing an authorization consistent with EPA guidance and TCEQ determinations.

The commission moves paragraph (e)(5) to paragraph (e)(4). The commission adopts paragraph (e)(5) to ensure that fugitive emissions from open-topped tanks or ponds are accounted for. Currently, open-topped tanks and ponds are authorized and found to be integral in site operations. While the amount of hydrocarbon liquids entrained in open-topped tanks and ponds may be minimal, as so often represented by industry, the agency believes that the amount of VOCs and H₂S emissions from these sources the agency believes can still actually be substantial. This is due to the open-topped tank or pond being exposed to the evaporative effects of the sun and wind. Therefore, the commission determines that VOCs or H₂S emissions from open-topped tanks or ponds are allowed up to a potential to emit equal to 1.0 tpy of VOC or 0.1 tpy of H₂S. The commission recommends using WATER 9 for estimating working and breathing emissions, since the program accounts for the evaporative effects of sun and wind.

Based on the commission's evaluation of actual site conditions and input from stakeholders, many OGS have open-topped tanks and ponds which are integral to site operations. In appropriate situations, these open tanks and ponds are acceptable and will only contribute in a negligible way to the site's emissions. In other cases, the amount of hydrocarbon liquids entrained in open-topped tanks and ponds may be sufficient to potentially result in a substantial amount of VOCs and H₂S emissions as the open-topped tanks or ponds are exposed to the evaporative effects of the sun and wind. Therefore, some reasonable limit is considered above which closed tanks are necessary. The commission is requiring that limit to be 1 tpy VOC and 0.1 tpy H₂S. Table 10 has been adjusted slightly in response to comments on separators and to clarify working loss from tanks. Process separators or vessels that would otherwise flash emissions to atmosphere are being associated with storage tanks may or may not have flash emissions. The flash emissions at oil and gas sites are part of the normal flow and filling processes which is working loss emission and the language has been clarified on this point. Storage tanks larger than 500 gallons must be submerged fill to avoid splash loss. The table was corrected for the typographical error noting the tanks and vessels with the higher volatility oil and condensate, ≥ 0.5 psia at maximum liquid surface temperature or 95 F (whichever is greater), does not have to be controlled until the tank or vessel has the potential to emit 5 or more tpy of VOC. Tanks and vessels emitting to atmosphere or destructive control must be light colored for the reasons noted with the exceptions specified.

The commission adopts (e)(5) which references the BACT requirements, now in Table 10. The proposed requirements of how to estimate cumulative emissions from any combination of equipment are adopted with no changes, but moved from the previous Table 11. The commission still believes there could be very minor gas streams that would be impractical to control. The adopted condition clarifies the requirement to account for every vent gas stream that contains 1 percent or more VOC to determine if routing all vent gas streams at the site to control is required. The commission determined potential from liquid streams was not practical to evaluate and was covered in the concept of evaluating gaseous vent streams. To address the potential for minor streams with 1 percent or more VOC concentration that are impractical to control, the commission will exempt a potential to emit of up to 1 ton per year of VOC from vent gas streams that are impractical to control at the site.

The new (e)(5) lists a site-wide requirement. The TCEQ believes that at a combined emission potential of 25 tpy VOC or more, the cost of the flare or other combustion control with some additional piping and gas moving cost is reasonable, and at oil and gas sites the potential for dramatically greater percentages of methane and ethane in the streams makes the combustion control even more reasonable. At 25 tpy over a 15 year life of the control device achieving 98 percent control would control 367.5 tons of VOC. At a low end Tier III BACT analysis for VOC control of \$8,000 per ton of control that equates to a cost of control of over \$2.9 million dollars for the equipment and annual operating cost. This could cover equipment costs to a million dollars with operating costs at \$10,000 per month. The TCEQ recognizes however that there could be sites with some very small streams that may contain more than 1 percent VOC that just considering the cost of piping would be impractical to control.

Table 10 addresses the BACT expectations for glycol dehydrators. These units have minimum design and operational restrictions. The dehydrators are a common facility at OGS and have the potential for high hourly emissions of BTEX. If the uncontrolled potential of a glycol dehydrator is greater than 10 tpy VOC, the design and operational requirements should reduce total VOC and BTEX emissions by at least 80 percent and as much as 98 percent. Due to these high potential emissions, the commission has included conditions to minimize the emissions from these process vessels once a substantial amount may be emitted. For glycol dehydrators with an uncontrolled potential greater than 50 tpy VOC, the design and operational requirements should reduce total VOC and BTEX emissions by at least 95 percent. For all estimates both controlled and uncontrolled the commission is willing to accept estimates provided by the GRI-GlyCalc program.

Table 10 has for clarity noted the regulated "Oil/Water" separators being addressed were units operating at atmospheric pressure. The requirements have not changed. Where the oil layer has lower volatility, < 0.5psia as specified the separator is simply enclosed with a small vent, 3 inch max, to keep the wind from stripping the VOC; and high H₂S concentrations need to be controlled. Then a cover is added on the oil layer for higher volatility oil, and 25,000 gallon plus units need to be treated as storage tanks. When pressurized entrained gases can flash these are to be treated as process separators. Note: per comments received process separators were combined with storage tanks due to the obvious similarity of operation where flash emissions are involved.

For process separators, the potential of VOC emission is minimized consistent with current permit BACT determinations and vents must be captured and directed to an appropriate control device with a minimum design control efficiency of at least 95 percent. Oil and water separators must have any sour stream controlled to at least 95 percent reduction in sulfur emissions. If separators have VOCs with partial pressure of ≥ 0.5 psia they must be controlled to at least 95 percent VOC control efficiency.

To encourage recovery, the commission has included a requirement of at least 95 percent control for VRSs if the system meets the technical requirements for these types of equipment.

Table 10 notes; fuel for all gas fired combustion devices is limited to sweet natural gas or liquid petroleum gas, fuel gas containing no more than ten grains of total sulfur per 100 dry standard cubic feet (dscf), or field gas. If field gas contains more than 1.5 grains (24 ppmv) of H₂S or 30 grains total sulfur compounds per 100 dscf the operator shall maintain records, including at least quarterly measurements of fuel H₂S and total sulfur content, which demonstrate that the annual SO₂ emissions from the facility do not exceed the limitations listed in the SP registration when field gas is used. The term gas fired was added to clarify this did not apply to liquid fueled devices authorized at the site.

Manufacturers of burners for boilers, reboilers, heater-treaters, and process heaters less than 40 MMBtu/hr firing rate have developed and companies have been using low NO_x burners that achieve 0.036 lb NO_x/MMBtu for several years. TCEQ has required these burners as BACT in recent case by case permits. Manufacturers have created burners that do not need flue gas recirculation (FGR) to achieve 0.036 lb NO_x/MMBtu and this has reduced the cost and installation problems for many facilities making it technically feasible for units that previously could only meet 0.06 lb NO_x/MMBtu because FGR was not possible. CO emissions tend to be well below 100 ppm on average with only occasional spikes. This allows for consistent low NO_x performance. This has been accepted as Tier I BACT.

Burner design has advanced in the past five years and manufacturers have developed ultra low NO_x burners for larger combustion units (>40 MMBtu/hr firing rate) and the TCEQ has permitted several facilities using this technology. The TCEQ recently approved a standard permit for boilers which requires 0.01 lb NO_x/MMBtu. The TCEQ is not aware of a technical limitation to applying this standard to units that are not strictly defined as boilers but use similar burners since these are burner designs and not boiler only technology. Manufacturers achieve ultra low NO_x in part through the use of internal or external FGR which is why it is not technically feasible for small units. CO emissions have remained low with the newer burners and current Tier I BACT is 50 ppm.

The standard permit also includes certain requirements for truck loading to minimize emissions. Consistent with the BACT discussion above, the commission is establishing capture and control requirements listed in Table 10. In Table 10, the standard permit restates requirements in standard permit (d) that cooling water never comes in direct contact with petroleum liquids or gases at the OGS, thus preventing emissions from being released into the atmosphere. This is a reasonable requirement and a basic engineering design and operation expectation to ensure cooling towers and heat exchanger equipment are in good working order, without gross stripping of VOCs to the atmosphere. To meet BACT the cooling water can either be at a higher pressure than the process, or the cooling water needs to be monitored monthly to check for leaks in the heat exchangers. Particulate matter is controlled by the required drift eliminators. To clarify new drift eliminators need to meet the common modern drift limit of ≤ 0.001 percent drift by design. Existing cooling tower drift eliminators would be based on manufacturer data or if unavailable the conservative EPA AP-42 factor from Chapter 13.4.

The commission has changed (e)(6) to clarify requirements for fugitive components. The commission adopts paragraph (e)(6) for requiring new and replaced fugitive components and instrumentation in gas or liquid service. Subparagraph (e)(6)(A) requires proper installation and maintenance of fugitive components, and consistent with the revised PBR, quarterly inspection. If a site has an uncontrolled potential to emit of 10 tpy VOC or 1 tpy H₂S or greater, BACT requires compliance with a fugitive monitoring program.

The commission proposes that paragraph (e)(6) is not applicable to components that are subject to NSPS requirements for fugitive components. In response to comments, the commission deletes the subparagraphs and clauses under paragraph (e)(6) and deletes and replaces the proposed language under paragraph (e)(6). The commission adopts language in paragraph (e)(6) to allow LDAR fugitive monitoring as an option in lieu of otherwise required fugitive monitoring, and the language indicates that Table 9 requirements are applicable if LDAR is chosen. The commission adopts language in paragraph (e)(6) requiring that all fugitive components be inspected on a weekly basis if LDAR is chosen as an option. The commission determines in response to comments that the initially proposed monitoring requirements for fugitive components were too stringent for fugitive components under the OGS standard permit. Therefore, the commission re-evaluates what is required for fugitive monitoring under the OGS standard permit. The commission determines that weekly physical inspections are necessary to add additional assurance that OGS meets claimed control efficiencies under LDAR. The commission believes that significant leaks are likely to be found more quickly during weekly physical inspections in comparison to only quarterly physical inspections. Additionally, the commission allows for claiming a control efficiency of 30 percent for components that have no LDAR control efficiencies by using weekly physical inspections.

The commission proposes subparagraph (e)(6)(A) to require that all seals and gaskets in VOC or H₂S service be installed, checked, and properly maintained in order to prevent leaking. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown. This shutdown does not need to be schedule or planned, just the next shutdown that occurs. A record of the emission calculation showing that it would release more emissions to shut down than the leak is emitting is required to be kept. 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. The commission deletes the language in subparagraph (e)(6)(B), as the language the commission adopts in subparagraph (e)(6)(A) addresses inspection requirements for all fugitive components and installation and maintenance requirements for all fugitive components are addressed in other language that the commission adopts in the OGS standard permit. Additionally, the commission determines that the initially proposed language is too vague. In response to comments, the commission adopts detailed language in subparagraph (e)(6)(B) to require that all fugitive components found leaking be repaired except when the repair would create more emissions than the repair would make during shutdowns; this is to ensure that any repair operations are not actually do more harm than good in increase site emissions levels. A record of the emission calculation showing that it would release more emissions to shut down than the leak is emitting is required to be kept. The commission determines in response to comments that the initially proposed repair requirements for fugitive components were too stringent for fugitive components under the OGS standard permit. Therefore, the commission reevaluates what is required for repair of leaking fugitive components under the OGS standard permit.

For components found to be leaking every reasonable effort must be made to repair leaking components immediately. The commission proposes subparagraph (e)(6)(C) to require that tank hatches that are not designed to be completely sealed need to stay closed (but not completely sealed in order to maintain safe design functionality) except for sampling or planned maintenance activities. The commission adopts subparagraph (e)(6)(C) as initially proposed and, in response to comments, adds gauging, loading, and unloading to the list of exceptions for when tank hatches do not need to be closed. The commission agrees open hatches can be necessary for safe loading and unloading of tanks. The commission agrees that open hatches can be a necessity for gauging of tank levels. The commission requires tank hatches to be gasketed and to remain in the closed position, but not necessarily completely locked down, to ensure that the tanks vapors are not freely allowed to escape through open gaps in the tank or tank's gaskets or seals.

The commission moves subparagraph (e)(6)(C) to subparagraph (e)(5)(C) to ensure that all fugitive components, including those from enclosed tanks, are kept in good working condition and are not found to be leaking liquids or gases. It is reasonable to assume that companies will not want to lose substantial amounts of product. As such, all components shall be physically inspected quarterly for leaks. This is to ensure that any gross leaks are immediately addressed. Additionally, all seals and gaskets in VOC or H₂S service shall be installed, checked, and properly maintained in order to prevent leaking.

Except for periods when sampling, gauging, loading, unloading, or maintenance is required, the commission is requiring tank hatches to be gasketed and remain in the closed position, but not necessarily completely locked down, to ensure that the tanks vapors are not freely allowed to escape through open gaps in the tank or tank's gaskets or seals. Lastly, the commission determines that hatches, valves, and lines integral to operations within the tank must be allowed to vent in order to prevent an excess pressure build-up within the tank and ensure the conditions within the tank are not hazardous. Therefore, some fugitive emissions must be allowed to escape from the tank is highly recommended in preventing the loss of valuable and useful product. In addition to recovering product, this would help to ensure site-wide protectiveness. The commission adds and adopts subparagraph (e)(6)(D) to require new and reworked valves and piping connections to be located in a place that is reasonably accessible for leak checking to the extent good engineering practices will permit and to require that underground process pipelines have no buried valves that cause fugitive monitoring to be impractical. Reasonably accessible fugitive components and not burying valves is good engineering practice and is necessary to ensure that leaking components can actually be fixed if found.

Paragraph (e)(7) of the standard permit include requirements that certain tanks, process vessels, and temporary liquid storage tanks containing VOC and H₂S be painted a color that minimizes the effects of solar heating. Tank color plays an important role in accelerating or minimizing VOC emissions from tank working and breathing losses. An estimate of emissions from working and breathing losses was calculated to evaluate the effect of color choice on the emissions from a storage tank and showed a 42 percent increase in VOC, benzene and H₂S emissions when a tank was red (or rust). In a typical tank example emission are released up to more than a ton more of total VOCs per year. While the argument has been made that solar absorption may not make a significant contribution to the amount of emissions from a single process vessel or storage tank, the results clearly demonstrate the paint color used is significant for emissions from working and breathing. It is estimated that there are tens of thousands of these tanks throughout Texas. Painting tanks with a low solar absorption rated color such as white will result in a significant cumulative reduction in statewide emissions. This has state-wide implications especially for counties currently in nonattainment areas or near-nonattainment areas. These results are consistent with the TCEQ Chemical Standard permits' previous BACT and BMP determinations of the last 20 years. The BACT requirement affecting temporary liquid tanks is a more recent determination, but these tanks can substantially contribute to VOC and H₂S emissions released throughout the state. In order to ensure air quality, all facilities authorized must minimize emissions to the greatest reasonable extent, thus the commission has included requirements to address color for permanent and temporary liquid and gas tanks and vessels which have a potential of 5 tpy VOC or are handling materials with a vapor pressure of 0.5 psia.

To effectively minimize the generation of air contaminants, tank color shall have a solar absorbance factor of 0.43 or less as referenced in Table 7.1-6 of AP-42. Additionally, the painting of tank surfaces should not only comply with the paint producers recommended application requirements if provided but also in sufficient quantity as to be considered solar resistant and thereby of good condition. However, for tanks and vessels purposefully darkened to create the process reaction and help condense liquids from being entrained in the vapor these requirements do not apply. Furthermore, up to 10 percent of the external surface area of the roof or walls of the tank or vessel may be painted with other colors to allow for identifying information and or aesthetics. Additionally, minimal amounts of rust may be present not to exceed 10 percent of the external surface area of the roof or walls of the tank and in no way may compromise the integrity of the tank. Lastly, for tanks or vessels in an area whereby a local, state, federal law, ordinance, or private contract predating this standard permit's effective date, established in writing, allows tank and vessel colors other than white, these requirements do not apply.

The commission has included the white or reflective color requirement for all new permanent tanks and vessels, or existing tanks and vessels with an increase in emissions. To further ensure air quality is preserved, all other existing tanks and vessels, plus all temporary liquid storage tanks brought to the OGS, must also be white by certain dates. The commission realizes that there may be thousands of existing tanks which may need to be painted after this standard permit becomes effective. The commission also recognizes that it is reasonable to offer a period of time to allow identification and inspection of all affected tanks, coordination with contractors and landowners, obtaining supplies, and completing the color adjustment. Therefore, the paragraph allows for up to 6 months for a renewal processed after January 1, 2016.

Paragraph (e)(8) outlines the design efficiencies for glycol dehydrators which are a common facility at OGS and have the potential for high hourly emissions of BTEX. If the uncontrolled potential of a glycol dehydrator is greater than 10 tpy VOC, the design and operational requirements should reduce total VOC and BTEX emissions by at least 80 percent and as much as 98 percent. Due to these high potential emissions, the commission has included conditions to minimize the emissions from these process vessels once a substantial amount may be emitted. For glycol dehydrators with an uncontrolled potential greater than 50 tpy VOC, the design and operational requirements should reduce total VOC and BTEX emissions by at least 95 percent. For all estimates both controlled and uncontrolled the commissions is willing to accept estimates provided by the GRI-GlyCalc program.

The commission has also clarified in subsection (e)(8) that other appropriate emission estimation methods must be used consistent with state and federal regulations and protocols.

Paragraph (e)(9) lists the requirements for process reboilers, heaters, and furnaces relied on to control emissions from waste gas streams. The operation and design of these units can vary greatly so the standard permit establishes a range of 50 to 99 percent destruction efficiency for VOCs and H₂S depending on the design and level of monitoring applied. Specifications for claiming 90 percent include details regarding where the waste gas is delivered to the flame zone or combustion fire box with basic monitoring. Values greater than 90 percent and up to 99 percent destruction efficiency may be claimed where enhanced monitoring and/or testing are applied to ensure practical enforceability. 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 is required to claim any run time beyond 50 percent.

Paragraph (e)(10)-(12) lists the requirements for control devices. Two common control systems used at OGS are vapor recovery systems (VRSs) and thermal destruction units. The commission establishes the expectations for VRSs. VRSs can cover different types of recovery systems, both by mechanical and chemical means. The most common type seen at OGS are the mechanical type, which use a compressor to collect the vapors and route them to a condenser, where the liquids are sent back to the tank and the gases to the sales pipeline. The other type is a liquid system, where the vapors are routed through a liquid and they are absorbed into the liquid. These systems are also vapor recovery systems because the vapor that has been absorbed can be recovered for profit. The VRSs that use mechanical means will be referred to as mVRUs and those that use chemical means will be referred to as IVRUs.

These systems have been evaluated by the commission, and its effectiveness proven if the liquid is tested and changed before the effectiveness reaches less than 95 percent. These systems can capture emissions from all VOCs tested. The system must meet the design parameters given to the manufacturer for capability to handle the stream going to the IVRU. If the system is tested as noted before and the liquid changed before the efficiency gets below either 95 percent or 98 percent as a result of sampling and testing, then these systems can be used at OGS. It is important to note that the schedule below is the maximum time allowed between sampling, depending on the claimed control efficiency. If the system has reached the maximum time limit, tested the system, and show that the system is still capturing at a greater efficiency than claimed, the liquid does not need to be changed immediately. If claiming 95 percent, the system can be tested 2 days later. If claiming 98 percent the system can be tested 1 day later. The current effectiveness can be extrapolated to determine the day the liquid will reach its minimum effectiveness (95 or 98 percent) and the liquid will need to be changed on that day. A record of the sampling, extrapolation, and liquid replenishment must be kept to demonstrate the effectiveness to the Regional office or Local program.

Thermal destruction units used at OGS include flares, thermal oxidizers, and vapor combustors. Paragraph (e)(11) addresses the use of flares at an OGS. One of the most common add-on control devices is the basic candlestick flare which the commission will continue to allow for normal emission control. With basic pilot flame or ignition monitoring, a destruction efficiency of 98 percent for VOCs and H₂S may be assumed and 99 percent may be assumed for VOCs containing no more than three carbon atoms that contain no elements other than carbon and hydrogen. These destruction efficiencies are consistent with the *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers*, October 2000. The key elements of the commission's acceptance are in the design that ensures the waste gas flow to the flare continuously meets the minimum heating value and maximum tip velocity as specified in 40 CFR §60.18, and compliance records that clarify how this is achieved. Additionally, the requirements of 40 CFR §60.18 are found to be sufficiently attainable and necessary to achieve proper combustion for emergency flares to be held to the same requirements. The rule clarifies that sufficient fuel gas should be added as necessary to make the gas adequately combustible, which means the heating value meets 40 CFR §60.18 at all times waste gas is flowing. 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. Flares, in accordance with 40 CFR §60.18, must also have a constant pilot flame to ignite the waste gas stream when it passes through a flare tip, and this is insured through the basic continuous monitoring of the pilot flames with thermocouples or equivalent infrared monitors. The commission will allow automatic igniters like continuous sparking devices in lieu of a pilot flame. For all flares, records of the time, date, and duration of loss of the flare pilot flame must be recorded. The commission does not require temporary, portable, and backup flares that operate less than 480 hours per year to meet the monitoring requirements.

The design still must show the flare will receive an efficiently combustible stream which would meet 40 CFR §60.18 for heating value and maximum tip velocity at all times the waste gas is flowing. The expectation is that the unique infrequent operation will generally be associated with personnel present to insure proper operation and a flame during these events. Flare systems that cannot meet the basic 40 CFR §60.18 at all times when waste gas is flowing, cannot be authorized for control under the PBR.

While the commission is aware of other forms of flares the commissions opted to represent the most commonly seen flare units in this evaluation. The commission recognizes that this is an ever improving form of control. For this reason, the commission hopes that, with the assistance of the regulated community and industry suppliers, we will better be able to authorize this ever improving control device.

The standard permit also requires that flares shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours, consistent with the 40 CFR §60.18 requirement. If visible emissions are present for longer than the time period stated here, the commission agrees this is an indication of incomplete combustion, demonstrating that the waste gas is not being sufficiently destroyed.

Acid gas flares which must comply with opacity limits and records in accordance with §111.111(a)(4), relating to Requirements for Specified Sources, regarding gas flares, are exempt from this visible emission limitation.

Thermal oxidation and vapor combustion control devices are allowable control devices in paragraph (e)(12). There is a wide variety of designs for this type of control ranging from simple partial enclosure of a flare tip to a fully enclosed ceramic heat retaining fire box with automated fuel and air control matched to the waste gas stream to maximize destruction. When properly designed, operated, and monitored as discussed below, the commission believes efficiencies from 90 percent to 99.9 percent can be effectively achieved. Any design where the applicant documents its device's expected efficiency with the variability of the waste gas streams to be controlled may claim up to 90 percent efficiency with any basic monitoring. Basic monitoring is a thermocouple or infrared monitor that indicates the device is working with a method of noting the hours of use. Devices may be shown to be efficiently designed using the principles of a combustible waste gas stream, with documentation showing the device will meet the requirements of 40 CFR §60.18 for the variability of the waste stream, or designed utilizing an engineered fire box that will hold the waste gas at greater than 1,400 degrees F for more than 0.5 seconds. These approaches may claim up to 98 percent destruction efficiency with intermediate monitoring. Intermediate monitoring is simply the continuous monitoring and recording of the exhaust temperature to insure the device is working at all times when waste gas is directed to the device, and the monitoring must show compliance with the 1,400 degrees F when applicable. The fire box or fire tube designs maintaining temperatures of 1,400 degrees F for more than 0.5 seconds may claim up to 99 percent if enhanced monitoring is utilized and the device is designed with ports and platforms to allow stack testing. This should ensure the fire box or fire tube is burning sufficiently hot enough and for a long enough time to achieve destruction. Enhanced monitoring requires the addition of a continuous oxygen or CO monitor and waste gas flow indicator in addition to the temperature monitor on the exhaust that will record at least 6 minute averages and show the device is within the design oxygen range or CO is less than 100 ppmv when waste gas is flowing. The commission recognizes that some devices with some waste gas streams can operate more efficiently than noted above or be reasonably efficient at lower temperatures with shorter residence times. Even with alternate temperatures and residence times, destruction efficiencies up to 99.9 percent may be demonstrated with enhanced monitoring and stack testing.

The TCEQ encourages pollution prevention, specifically source reduction, as a means of eliminating or reducing air emissions from industrial processes. Sites should consider opportunities to prevent or reduce the generation of emissions at the source whenever possible through methods such as product substitutions, process changes, or training. Considering such opportunities prior to designing or applying “end-of-pipe” controls cannot only reduce the generation of emissions, but may also provide potential reductions in subsequent control design requirements (e.g., size) and costs.

Paragraph (f), moved from paragraph (g) in the proposal, has been renamed and consolidates all registration, revision, and renewal requirements. The registration requirements are modified from the current OGS standard permit to provide flexibility and only necessary processing of paperwork by industry and the TCEQ.

Paragraph (f)(1) explains that existing facilities or groups of facilities authorized under the oil and gas standard permit are not required to meet the requirements of this standard permit, with the exception of planned MSS, until the next renewal after December 31, 2015. This allows for ample time for any site changes, needed to meet the requirements of this standard permit, to be planned and executed.

Paragraph (f)(2) explains that if an existing site authorized under the oil and gas standard permit is registering planned MSS emissions with no changes at the site, a revision is not required and no paperwork is required to be submitted. Instead, records showing compliance with paragraph (i), relating to planned MSS, must be maintained and be available upon request by agency personnel

Paragraph (f)(3) simply states that facilities, groups of facilities or planned MSS from facilities registered under this standard permit cannot also be authorized by a permit under §116.111 of this title. This is part of the agency objective of creating site-wide authorizations.

Paragraphs (f)(4) through (f)(6) include a different approach than was originally proposed. The commission originally proposed detailed registration and approval before any changes could be implemented at a site. Now a notification is only required prior and only afterwards, when the most accurate data is available, is a detailed registration required. Paragraph (f)(4) requires notification to be submitted through the e-permits system (or hard-copy if e-permits system not available) prior to construction or implementation of changes for any standard permit project along with a small processing fee of \$25 for small businesses (as defined in §106.50) or \$50 for all others. This requirement gives flexibility to industry in timing and ensures the appropriate authorization method is chosen. It also ensures that the commission has the opportunity to audit emission estimates within a reasonable period of time from start of operation.

Paragraph (f)(5) goes through the registration requirements. A 90 day limit for registration with a Form PI-1S after start of operation or implemented changes (whichever occurs first) is established. The 90 day registration deadline is set with consideration to the time it typically takes for an operator to determine the production of a well or group of wells. The registration application must include emission estimates based on site specific data (or representative data where appropriate) that demonstrate compliance with all applicable emission limits. The appropriate fee of \$475 for small businesses or \$850 for all others must also be included in the registration. It is also noted that once notification is provided, construction may begin with the condition that operations may continue after registration provided there are no objections within 45 days.

Paragraph (f)(6) explains that if emissions increase at a site, the site may change the authorization between the oil and gas PBR (two levels) and Standard Permit. This must be done within 90 days from either the initial notification or from a change of production or installation of additional equipment. It is the expectation of the commission that if a site that did proper notification for the intent to construct a site under this Standard Permit, and the site once constructed does not qualify for this Standard Permit, and must instead apply for a NSR case by case permit under §116.110, the site must cease operation until the proper authorization is received.

Paragraph (f)(7) explains that all Standard Permit registrations, revisions, and renewal applications can be done by submitting the Form PI-1S. It is also stated that no fee is required to update representations with no increase in emissions if done so within six months after issuance of the permit.

Paragraph (g) explains that any claim under this standard permit must comply with all applicable requirements of 30 TAC §116.610; §116.611, Registration to Use a Standard Permit; §116.614, Standard Permit Fees; and §116.615, General Conditions. It is specifically notes that this standard permit supersedes the notification requirements of 30 TAC §116.615, General Conditions and the emission limitations of 30 TAC §116.610(a)(1).

Paragraph (h) addresses overall limits for an OGS under standard permit based on the largest amounts of air emissions which have been shown by the commission's impacts analysis to be protective and meeting ambient standards. Paragraph (h) limits the hourly and annual emissions for OGS registered under this standard permit based on the protectiveness review and impacts tables completed by the commission. The commission created and utilized pollutant specific impacts tables based on the generic modeling results and the most stringent ESL or air quality standard. The hourly limits are for both steady-state and periodic releases. The commission believes that the limits are set reasonably high enough to allow for high short term peaks in emissions from events such as blowdowns and liquid loading. Since both normal continuous type operations as well as planned MSS operations and other short term high emissions events must be demonstrated to be protective (as stated in paragraph (k)), the commission also believes these limits are alright to be set as high as they are; the actual site limits may be much lower based on the impacts review determined limits.

In response to comments, the commission re-evaluates and revises the generic OGS evaluation used for modeling and development of the impact tables. The commission bases the new VOCs limits on the revised generic OGS evaluation and on the necessary, subsequently developed tables due to the revised generic OGS evaluation and due to comments about the modeling methodologies for the tables themselves. In response to comments, the commission revises the VOC limits to account for various mixtures and corresponding ESLs (crude oil, condensate, natural gas) as well as steady-state and periodic intermittent releases. For all analyses involving the pollutant specific impacts tables, a distance of about 1 mile (5,500 ft) was used as the distance to receptor or property line.

Total VOC emissions are limited to 250 tpy, which is the limit for being considered PSD major for non-named sites. Total steady-state and low pressure periodic crude oil or condensate emissions are limited to 145 lb/hr. The greatest sources of crude oil/condensate emissions from oil and gas sites were found by the commission to be flash from storage tanks and tank loading, with the typical tank height being 20 feet and loading assumed to occur at a height of 10 feet and blowdowns.

From the pollutant specific impacts table, for truckloading, the values from the condensate and crude oil charts are 140.00 lb/hr for 10 feet height loading, 145.83 lb/hr for a 20 feet height tank hatch, and 145.8 lb/hr for a 10 ft height blowdown at a distance to receptor of 5,500 feet. Total steady-state and low pressure periodic natural gas emissions are limited to 750 lb/hr. For higher pressure scenarios and releases, the 10 foot release height at a distance of 5,550 feet to receptor results in a limit of 1635 lb/hr for natural gas and 318 lb/hr for condensate and crude oil. The greatest sources of natural gas emissions from oil and gas sites were found to be flash from storage tanks, tank loading, blowdowns, purging, and pigging. From the pollutant specific impacts table, for truckloading, the values from the natural gas charts are 720.0 lb/hr for 10 feet height loading, 750.0 lb/hr for a 20 feet height tank hatch, and 750.0 lb/hr for a 10 feet height blowdown at a distance to receptor of 5,500 ft. Based on the modeling tables for the appropriate emission sources for VOCs, benzene emissions are limited to 7 lb/hr and 10.2 tpy.

Hydrogen sulfide emissions are limited to 10.8 lb/hr and 47 tpy. There are many sources of H₂S at oil and gas sites including tanks, loading, fugitives, blowdowns, and flares combusting sour gas. From the pollutant specific impact tables, for a 40 ft flare at a distance to property line of 5,500 ft, the values are 10.8 lb/hr and 47.3 tpy. Sulfur dioxide emissions are limited to 93.2 lb/hr and 100 tpy. The greatest sources of SO₂ emissions from oil and gas sites were found to be engines and flares combusting sour gas. From the pollutant specific impacts table, for a large engine, greater than 2,000 hp, at a 40 ft stack height and at a distance to property line of 5,500 feet, the value is 93.2 lb/hr. The 250 tpy limit was chosen because it is the limit for being considered PSD major for non-named sites.

Nitrogen oxide emissions are limited to 121 lb/hr and 250 tpy. The greatest source of NO_x emissions at oil and gas sites was found to be engines. From the pollutant specific impact table, for an engine between 1,500 to 2,000 hp with an 18 ft stack height and at a 5,500 ft distance to receptor, using the 0.50 NO₂/NO_x ratios, the value is 120.8 lb/hr. The 250 tpy is the limit for being considered PSD major for non-named sites.

Carbon monoxide emissions are limited to 104 lb/hr and 250 tpy. The 250 tpy is the limit for being considered PSD major for non-named sites. The 104 lb/hr limit is about double 250 tpy converted to lb/hr assuming continuous operation. The reason greater than the continuous number is allowed is to allow periodic releases and also to create a reasonable limit since the modeling results show that even larger amounts of CO are protective than is reasonable to have as a limit for a standardized authorization.

PM₁₀ and PM_{2.5} emissions are limited to 28 lb/hr and 15 tpy. The greatest source of particulate matter emissions from oil and gas sites was found to be engines. From the pollutant specific impact table, for an engine between 1,500 to 2,000 hp with an 18 feet stack height and at a 5,500 feet distance to receptor, the value is 28.1 lb/hr. The 15 tpy limit was chosen as a reasonable limit shown to be protective from the impact tables and less than any oil and gas registration seen by the commission to date.

Paragraph (i) lists specific MSS activities authorized and the associated limits. Paragraph (i)(1) lists the applicability dates and schedules for authorizing planned MSS activities, and notes that authorization under this standard permit is voluntary until January 5, 2012. For existing, properly authorized, OGS, MSS emissions do not need to be addressed until January 5, 2012, unless modifications are made. If modifications are made to an existing OGS on or after the applicable effective date of the standard permit, then MSS activities and associated emissions for that site need to be either registered or addressed in a registration.

The commission has limited information on the various planned MSS activities which occur throughout the diverse oil and gas industry and is requesting comments and technical information on activities and potential emissions from planned MSS. To assist companies in calculating their MSS emissions the agency is building MSS estimation methods into the emission calculations spreadsheet and published the draft on the agency website for external stakeholder input as of October 29, 2010. The commission will also provide checklists and guidance documents that will be available on the TCEQ website. In addition, the commission is planning on sponsoring short workshops around the state to assist companies in preparing registrations and compliance records before the effective date of the standard permit. The commission requested comments and technical information on activities and potential emissions from planned MSS because of the limited information available on the various planned MSS activities which occur throughout the oil and gas industry. The commission did not receive any information in response to this request and the standard permit has not changed.

The commission adopts paragraph (i)(2) to ensure that all chemically common emissions are evaluated for protectiveness. Emissions from control devices used for planned MSS (permanent or portable) are included for emission limits evaluation. The VOC for planned MSS emissions under worst-case operating conditions and all contributing emissions must be evaluated for total hydrocarbons as condensate, natural gas, and benzene. Paragraph (2) specifically lists the most commonly expected activities which may contribute to emissions during these events. In most cases, emissions from blowdowns or purging do not occur simultaneously with production emissions, so the weighted fraction method of impacts evaluation is not commonly needed. There are certain expected planned MSS activities and associated emissions which also have the likelihood of quantifiable hourly and annual emissions. The commission has revised paragraph (i)(2)(C) in response to comments and has determined that references to §106.263 are not necessary as control expectations are covered sufficiently by paragraph (e)(8) - (12).

Planned MSS activities with negligible emissions are authorized by paragraph (i)(3) and are limited to the following: routine engine component maintenance including filter changes, oxygen sensor replacements, compression checks, overhauls, lubricant changes, spark plug changes, and emission control system maintenance in combination with any other activities; boiler or thermal oxidizer refractory replacements and cleanings; heater and heat exchanger cleanings; lubrication oil level checks; glycol draining and refilling; pump, compressor, heat exchanger, vessel, water treatment systems (cooling, boiler, potable), and fugitive component maintenance after associated blowdowns and degassing; use of aerosol cans, soap, and other aqueous based cleaners; pressure relief valve testing; calibration of analytical equipment; instrumentation/analyzer maintenance; replacement of analyzer filters and screens; and cleaning sight glasses. These other planned MSS activities require recordkeeping, but no emissions quantification unless specifically requested by the commission. Other planned MSS activities with negligible emissions are based on the commission's experience with chemical plant MSS for NSR permits, refinery MSS for NSR permits, and oil and gas MSS and process knowledge for oil and gas registrations. The commission requested comments and further information on the physical design parameters and operational activities which occur at OGS to accurately predict other planned MSS activities with negligible emissions not listed here. The commission did not receive any information in response to this request and the standard permit has not changed. If qualitative, quantitative, and/or updated information about other MSS activities with negligible emissions becomes available in the future or if emissions are found to actually be more than negligible, the commission may reopen this standard permit to reevaluate other MSS activities with negligible emissions. The commission has removed amine and other treatment chemicals replacement (except glycols) and hot oil treatments from this paragraph.

The commission evaluated the potential for emissions from replacing amine and other treatment chemicals and does not believe there is sufficient emission potential to warrant accounting of this activity for a standard permit. The commission is not comfortable adding an exemption for heavier oils or smaller vessels for MSS because the approach to clearing is not regulated in the standard permit. Liquid heels and clinging in vessels can represent significant emissions if forced into the atmosphere for clearing or cleaning purposes.

Paragraph (i)(4) covers a very specific circumstance the commission has reviewed. This paragraph is included as an option, not a requirement, for larger OGS with multiple engine/compressor sets to authorize additional piping and material transfer to allow ongoing operations when one engine at a plant must shutdown. In these instances, the shutdown would not have a large amount of associated purging (blowdown) of VOCs, since the materials would be shifted to another part of the OGS. This subsection has been updated to state that engine/compressor shutdowns shall result in no greater than 4 lb/hr of natural gas emissions instead of stating that the shutdowns shall not result in emissions. This value should allow for a small amount of emissions from shutdowns and still includes a reasonable amount of VOC emissions justifiable to be authorized under this circumstance. The 4 lb/hr value is consistent with the value from the natural gas impacts table for fugitive dispersion characteristics at the shortest distance, 50 ft, and a 3 ft release height. Startup emissions may also occur as air is purged from the compressor with a small amount of the VOC stream. If these streams are then captured and sent to a control device with a destruction effectiveness of 98 percent, they are substantially minimized. If companies operate in this manner, the registration should specify all details and emission estimates.

The commission requested comments and technical information on activities and potential emissions from planned MSS because of the limited information available on the various planned MSS activities which occur throughout the oil and gas industry. The commission did not receive any information in response to this request and the standard permit has not changed. If qualitative, quantitative, and/or updated information about other MSS activities and associated emissions becomes available in the future, the commission may reopen this standard permit and/or the oil and gas standard permit to reevaluate other MSS activities and associated emissions.

The records, monitoring, and sampling requirements in **paragraph (j)** of the standard permit are intended to provide a clear, understandable set of expectations in order to easily establish compliance. Providing explicit requirements meets the test of practical enforceability, an essential element for all commission authorizations. Compliance with all applicable regulations is ensured through sampling (specified in Table 7 in paragraph (m)), monitoring and recordkeeping (specified in Table 8 of paragraph (m)). All necessary records, which include documentation of all sampling and monitoring, must be maintained and contain sufficient information to demonstrate compliance. These records are important to determine the following: verify all information used to estimate emissions; verify that emissions meet applicable limits; show current equipment and processes; explain equipment or process changes and associated effects on emissions; and show equipment is properly operated, monitored, maintained, and inspected. Any records that are kept for other purposes but demonstrate the necessary information are sufficient and no other records are required.

In response to comments, the commission adopts a requirement for a monitor for Boiler, Reboilers, Heater-Treater, Process Heaters, and Internal Combustion Engines Gas Fired Turbines over 500 hp. The commission proposes a run time meter for Boiler, Reboilers, Heater-Treater, and Process Heaters. In response to comments, the commission adopts a requirement for a monitor only if a registration relies on less than full year operation and maximum capacity when calculating emissions. Also, the adopted standard permit expands the examples of process monitors beyond run time meters. The commission's intent is to require a practically enforceable permit condition for facilities that are registered at less than full potential to emit in cases such as artificially limiting operation to avoid stricter rules. The commission proposes a run time meter for Internal Combustion Engines. In response to comments, the commission adopts a requirement for a monitor only if a registration relies on less than full year operation and maximum capacity when calculating emissions. Also, the adopted standard permit expands the examples of process monitors beyond run time meters. The commission's intent is to require a practically enforceable permit condition for facilities that are registered at less than full potential to emit in cases such as artificially limiting operation to avoid stricter rules. Also, the adopted standard permit expands the examples of process monitors beyond run time meters. The commission proposed a run time meter for Gas Fired Turbines. In response to comment the commission adopts a requirement for a meter only for turbines greater than 500hp and only if the registration relies on less than full year operation and maximum capacity when calculating emissions and expands the examples of process monitors. The commission's intent is to require a practically enforceable permit condition for facilities that are registered at less than full potential to emit in cases such as artificially limiting operation to avoid stricter rules. The commission proposes a fuel flow meter for all gas uses at the site. In response to comment, the commission adopts a requirement for a fuel flow meter if less than 8,760 hours per year are used in calculating emissions from fired units. The commission's intent is to require a practically enforceable permit condition for facilities that are registered at less than full potential to emit in cases such as artificially limiting operation to avoid stricter rules. Also the commission clarifies that no records of hours of operation must be kept for engines that have no sampling requirements in Table 7.

Each specific sampling, monitoring, and recordkeeping requirement varies based on related effects, accurate compliance demonstrations, and protectiveness and includes the following items: a site layout including the configuration of all equipment and process units within the site must be maintained; the property line and nearest off-site receptors must be shown because impacts of pollutants are based on the property line and receptor distances; any changes to the site layout need to be recorded in case the change affects emission impacts, for example if the distance of a unit to a receptor or property line changes; and a site process description and process flow diagram is needed to ensure that all emission points are accounted for and authorized. This documentation should clearly show all process and waste streams and the inputs and outputs of the total site and individual units or processes. Any process changes need to be recorded in case the change affects emissions. Site production or collection must be recorded over time because this is the basis for emission estimates. It is necessary to maintain records of the types of service (i.e. natural gas, oil, condensate, and water) being processed at a site in order to ensure that emission limits for each component have not been exceeded and that all constituent emissions are represented. This information is important to determine appropriate maximum acceptable emissions of all authorized facilities.

The sampling requirements are the minimum requirements customary to the applicable units. Sampling ports and platforms need only be installed when needed to obtain the samples required to demonstrate compliance. All sampling and testing including the facilities and equipment necessary to conduct the sampling are at the expense and the responsibility of the holder of the authorization. To conduct sampling, proper ports and platform access must be part of the design of the process equipment and their vents and stacks. Basic specifications on stack sampling are explained in the Sampling Procedures Manual in “Chapter 2, Stack Sampling Facilities.”

Where any applicable sampling is required, for example to establish a high destruction efficiency to meet impact requirements, the testing should be conducted as soon as possible but no later than 180 days of the initial start of operation of implementation of a change which required the registration. This time frame allows for scheduling testers, and coordinating with the Regional Office for working out process startup issues of new and modified equipment. Standard EPA reference methods are required to be used for the sampling and analysis and they include some quality assurance and quality control procedures. Minimally, three one hour test runs should be conducted and averaged to demonstrate compliance, additional testing may be appropriate to establish different operating parameters for different operating scenarios. The TCEQ Regional Office must be provided various federal NSPS and NESHAP standards, other standard permits, typical permit conditions, as well as the Level 2 confirmation of emissions. All sampling must follow the TCEQ Sampling Procedures Manual and the appropriate EPA Reference Methods to ensure consistency and quality assurance of evaluation techniques. The Regional Office shall be afforded the opportunity to observe the sampling and a minimum 30 day pre-sampling notice must be provided. The notice must include a date for a pretest meeting, the sampling date, the sampling firm, the specific equipment, methods and procedures to be used, the procedures and parameters to determine and record operating rates and parameters affecting the emissions during the sampling period, and any proposed deviations to the prescribed sampling methods so that independent audit capabilities are maintained by the commission. To allow for possible sampling observance, adjustments in sampling techniques or methods, or to provide other necessary guidance, the permit holders must contact the TCEQ when testing is scheduled, but not less than 30 days prior to sampling. Notification and opportunity for coordination with regional stack testing staff is also within the ordinary arrangements considered reasonable in stack testing requirements. After initial coordination, companies and TCEQ staff routinely work out schedules that are amenable to all parties. Following these procedures, using standard methods and communication with the Regional Office is important to avoid costly additional or retesting.

Once completed, reports should include information specified in “Chapter 14, Contents of Air Emission Test Reports” of the Sampling Procedures Manual. The report must be sent to the Regional Office within 60 days of the testing. Stack test reports submission requirements have been simplified in that one original and one copy be sent to the Regional Office. The TCEQ Regional Director is authorized to allow alternate sampling facility designs, and deviations to sampling procedures, but the authorization holder must have written approval to make the change. Chapters 2 and 14 portions of the Sampling Procedure Manual. Finally, results are required to meet National Environmental Laboratory Accreditation Conference (NELAC) certification requirements found in 30 TAC Chapter 25, Environmental Testing Laboratory Accreditation and Certification. That does not mean all data must come from a NELAC certified lab. Rather the Chapter 25 rule explains when that certification must be applied. This requirement in the standard permit is no more than what the rule requires.

Sampling of gas and liquid streams from appropriate process sampling points is required in order to determine composition or other properties needed to estimate emissions such as heat content, specific gravity, and vapor pressure. It is essential that stream lab analyses/reports include a measurement of H₂S, individual HAPs, and at least all those hydrocarbons up to at least 10 carbon atoms per molecule (C₁₀+). Proper quantification of emissions can only be done when information is as accurate and complete as possible. Records of gas and liquid analyses must be maintained and updated over time to represent current site specific information. Site specific information is needed because although one well may pull from the same formation and field as another well, formations can vary throughout and minor variations in the composition can greatly affect emissions. A representative sample can be used if the sample meets the defined criteria. The commission will have a protocol that has gone through a comment period. The representative sample must meet those requirements. Samples should be taken prior to any treatment for the most accurate information for estimating emissions. If a sample is used that is from another point in the production, then the emissions will not be representative. This is due to the fact that the character and composition will be different than what is being treated. The emission prediction models will only estimate emissions based on the input parameters. If these do not match then there is no way to verify how accurate the emission estimates are. Correct parameters are needed in order to verify that the site meets the standard permit being claimed.

Emissions calculations should be supported with as much associated site-specific or defined representative sampling and testing needed to perform such emissions calculations (e.g. a site with an outlet gas stream from a high pressure separator, outlet gas stream from a glycol unit, outlet gas stream from an amine unit, and outlet gas stream from a low pressure separator may require sampling and testing for all four gas streams to sufficiently complete emissions calculations for fugitive emission from piping components). Acceptable outputs from emissions calculations can be used in place of testing (e.g. the outlet gas flow speciation from the emission calculations output of GLYCalc 4.0 software could be used for emissions calculations for fugitive emissions from piping components). Review of available information indicates that sampling once a year is a reasonable frequency for monitoring changes to the composition of the well. Lab analysis is needed for proper quantification of emissions, specifically HAPs and H₂S. As needed and required by (j)(8), a pressurized gas, pressurized liquid, stock tank liquid, and stock tank vapor sample needs to be taken and analyzed. Failure to sample at the appropriate location can result in a mischaracterization and quantification of emissions.

The commission recognizes the importance of using information that is as accurate as possible in estimating emissions from oil and gas production and processing sites. However, the commission also recognizes that (1) it is impractical to request site specific samples for pre-construction authorizations and (2) for existing sites, it may be impossible for the analytical labs to process all the samples needed within the allotted time frame. The commission agrees that these are valid concerns and has taken them into account for the standard permit adoption. The commission is allowing 90 days after start of operation or implemented changes (whichever occurs first) for the larger, higher-emitting sites, which qualify for the Standard Permit, to be registered.

It may still be seen as unreasonable for an applicant to determine which level of authorization is appropriate and be registered within either the 90 or 180 days specified in the standard permit. The commission, however, believes it is reasonable that an applicant can make a general projection as to whether the site emissions are within the standard permit limits, based on the type and amount of equipment. It should be noted that even with these registration timelines stated in the standard permit, site specific analyses may be requested at any time by anyone with jurisdiction, including regional and local personnel.

The criteria for what is considered a representative sample will be a in a guidance document issued by the Air Permits Division of the TCEQ.

Representative analyses are not acceptable for H₂S content; site specific sampling is required. Representative analysis will not work for determining H₂S content of the stream. Each site will have to know the content for that stream, since it can vary greatly in a field and formation. However, to minimize cost a simple test such as a stain tube or dragger tube can be used. Sites with H₂S too high to use these simpler types of test methods will have to have an analysis done by GC. It is recommended that multiple similar sites to the actual site are reviewed and the site that yields the highest estimate of emissions be used as the representative site. This will insure that the actual site emissions are most likely less than the site actually sampled. It is also recommended that the representative analysis be as recent as possible, but no more than a few years old, in order to provide the most current and accurate data. It is very strongly encouraged that representative lab analysis reports state the field and reservoir/formation from which the sample is produced from. This is necessary in order to document that both the representative site and actual streams sampled are from the same producing field and reservoir/formation. At the time of sampling, it is suggested that this information is given to analytical lab personnel and asked to be reported in the analysis. It is also important to note that site specific analyses may be requested at any time by anyone with jurisdiction, including regional and local personnel.

Laboratory extended VOC Gas Chromatograph (GC) analysis at a minimum to C10+ and H₂S analysis for gas and liquids for the following shall be performed and used for emission compliance demonstrations: separator at the inlet; dehydration unit prior to dehydrator; amine unit prior to sweetening unit; tanks for liquids and vapors; and produced water or brine/salt water at the inlet prior to storage.

A laboratory extended VOC GC analysis must be speciated to a minimum C10+ in order for such software programs as E&P Tanks 4.0, GRI-GlyCalc, and AmineCalc to accurately calculate emissions such as benzene, from their prospective units. For example, in order for emissions from flashing to be calculated properly with the E&P Tanks 4.0 program, a speciated analysis to C10+ along with its Molecular Weight (MW) and Specific Gravity is required. To verify the necessity for this extended analysis the E&P Tanks 4.0 program was run based on an analysis speciated out to hydrocarbons with 6 carbon atoms per molecule (C6) (representing only 35 percent of the needed material). The resulting uncontrolled emissions based on this analysis (normalized to reflect 100 percent) yielded emissions levels so high that impacts standards would not be attainable without serious control measures. Similarly, it has been determined that for sites which employ a glycol dehydration unit (where benzene emissions are of concern) to take a conservative estimate of benzene emissions would surely trigger MACT applicability. MACT applicability requires the applicant to put in place further control requirements which in the long run would be more expensive to maintain and operate than for an extended C10+ analysis to be attained. In summary, in order for an applicant to accurately represent the impacts of emissions from their respective site, a speciated analysis to C10+ must be utilized. While it is possible for an applicant to use an analysis speciated to C6, it would require the applicant to overestimate impacts from emissions such as BTEX. This over estimation could needlessly trigger federal applicability standards resulting in greater cost.

If the sampling is done at the representative worst case scenario, then worst case emissions should be represented. Historically, permitting is always based on worst-case scenarios. Sampling needs to be attained from the proper sampling locations in order to have accurate inputs for the appropriate emissions calculation methods. Sites subject to the standard permit must demonstrate how they comply with the emission limitations of H₂S by obtaining an analysis of the percentage/volume of H₂S of the site. In order for a site to demonstrate that they meet the requirements of the H₂S emission limitations of the standard permit, one or more analysis or estimate must be obtained. The choice of analysis is the Tutwiler, Stain Tube (of which there are many types and brands, all are acceptable), or full sulfur analysis. The traditional method was one analysis on the incoming site's gas stream and to use that analysis percentage in every other stream at the site for an emission estimate. Modern computer programs and sampling have demonstrated that this method is not very inaccurate. In fact, the H₂S concentration in the emissions to the air may increase many times from the incoming H₂S liquid concentration to a tank during flash. At a minimum if no computer program is used to estimate H₂S flash emissions at a sour site, the pressurized flash sample taken for VOC should include an H₂S analysis along with the daily production rate or sampling the H₂S vent concentrations from a crude oil or condensate storage tank along with the estimated VOC tank emissions should be completed to estimate H₂S flash emissions. Sour sites with produced water should calculate using some basis, sample or use a computer program to estimate the produced water H₂S emissions. It is expected that the H₂S emissions be established for each facility in order to demonstrate compliance with the emission limitations. The commission continues to seek comments on H₂S sampling and estimation at OGS.

Required site-specific or defined representative gas and liquid analysis goes together with the record requirement for equipment specifications. The volumes and pressures, material compositions of the vessels to be depressured, purged or degassed and emptied for MSS are directly related to the emission rate estimated. The control equipment specifications from the manufacturer or design should match with the flow, temperature and pressures measured and coming process equipment for normal and, as applicable MSS, and define the appropriate compliant ranges for parameters that need to be monitored. This record explains the site operations and emissions and how they designed compliant for the worst case emission scenario.

Fugitive component monitoring and associated documentation is required because it promotes the early detection and repair of process leaks, which reduces emissions, increases safety, and can prevent product loss. Whether fugitive component monitoring encompasses BMP or LDAR program, it is necessary to maintain records of detailed fugitive component monitoring plans and practices, as well as to record LDAR program results, in order to demonstrate that fugitive emissions are being well monitored and have not exceeded applicable emission limits. These records will also justify any reductions taken on emission estimates. It is necessary to maintain records for the addition and/or replacement of piping components in order to determine how it will potentially impact fugitives and associated emissions, what additional facilities should be included in monitoring programs. Records of standardized methods or recommendations for operational specifications, maintenance schedules, BMP, and LDAR programs are necessary in order to compare with actual procedures. Records of equipment specifications are necessary inputs for emission estimates and also help confirm that equipment is operated as designed. Records of all equipment replacements and repairs are necessary to be maintained because of the effect on emissions. It is necessary to maintain records for like-kind equipment replacement especially in order to demonstrate that the replacement equipment does not significantly affect operations and emissions at the site. These records should include equipment specifications and operations and a summary of emissions (type and quantity). Site impacts should be reevaluated if there is a change in emissions. These records ensure that equipment is kept in good working order and corresponding emission quantifications are accurate for the OGS.

Exhaust stack sampling and testing must be performed as required for a variety of units, including engines and thermal control devices designed for and claiming high efficiency, to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere. Certain parameters may need to be monitored and recorded during the stack testing because of their effect on emission rates. Testing and quarterly performance evaluations of engines are included to ensure proper on-site operation of engines. On-site testing and evaluations will be needed to verify that engines are being operated within manufacturer or company-determined specifications and to ensure that public health and welfare is being protected by demonstrating that emissions from engines are not exceeding acceptable claimed or certified emissions. To provide flexibility and reduce unnecessary sampling at a site, the commission is requiring that only 50 percent of identical engines must be sampled initially, with the remaining identical units sampled at the biennial timeframe with this alternating pattern continued forward. Records would need to be maintained for each engine to ensure that when an engine moves off-site, the next owner or operator has the option to follow the alternating schedule, otherwise, the engine would have to be stack sampled within 180 days of arriving at the new site. In response to comment, the commission adopts a clarification that initial sampling for engines may be performed on-site if no previous sampling reports are available. Also, the commission adopts a clarification that initial and periodic sampling is not required for emergency engines and that idled engines do not need to be restarted solely for the purpose of testing. Additionally, the commission adopts language to allow a period of time after restarting an engine for sampling to occur in order to accommodate the scheduling issues noted in the comments. Proper on-site operation would include demonstration of compliance with health-based impacts for total VOC (as natural gas) emissions and property line standards for NO_x emissions. Proper on-site operation would include demonstration that controls are operating properly, including testing for emissions of formaldehyde. However, the TCEQ is aware of significant technical hurdles to implementing a massive, state-wide sampling program for formaldehyde from oil and gas industry engines given the complexity of the approved testing methods, the time required for each test, and the availability of sampling equipment for formaldehyde. For these reasons, the TCEQ is not requiring individual engines to be tested for formaldehyde but the TCEQ intends to work with engine manufacturers to establish appropriate emission factors for specific engine models.

The commission proposes initial sampling requirements for VOC from engines turbines in Table 7, "Sampling and Demonstrations of Compliance." In response to comment, the commission adopts no requirement for sampling VOC from engines and turbines. The commission believes carbon monoxide (CO) is an adequate surrogate for VOC and that the initial sampling for CO combined with quarterly monitoring for CO at larger emission sites holding a federal operating permit represents appropriate VOC monitoring. The additional cost of monitoring for VOC has been eliminated but registrations still must contain appropriate estimates of emissions. Periodic monitoring of engines is needed to ensure ongoing performance. The methods described in the proposal economical and clear indicators of these units meeting emission limitations. Engine performance can degrade over time and biennial testing is too long a period to ensure proper condition and consistent emission quantification. This requirement is consistent with permit conditions, including those included in issued Existing Facility Permits for grandfathered facilities. Additionally, engine degradation can lead to increases in formaldehyde emissions. In lieu of sampling for formaldehyde, these periodic tests for CO, a qualitative indicator of good combustion, will ensure maintenance is reducing this formaldehyde increase from occurring. The commission adopts a clarification in the engines periodic evaluation standard permit of Table 7 to state that these evaluations only need to be performed on engines that have a standard in Table 6. The commission proposed quarterly periodic evaluations for all engines with a standard in Table 9. In response to comment, the commission adopts quarterly periodic evaluations only for engines at sites that have a federal operating permit.

Overall, quarterly testing under the OGS standard permit is less stringent or as stringent as associated periodic monitoring choices in the oil and gas GOPs. Since sites with federal operating permits necessarily emit more pollution than sites without those permits, the commission believes it is appropriate to require enhanced monitoring. The commission proposes the use of only portable analyzers conforming to federal quality assurance procedures for periodic evaluations. In response to comment, the commission adopts the use of portable analyzers operated according to manufacturer's instructions or the use of stain tubes for periodic evaluations. The commission agrees with commenters that prescriptive analyzer methodology like Conditional Test Method 034 may not lead to any different results than a company-developed method. However, the commission adopts language that any modifications to the portable analyzer manufacturer's instruction such as calibration procedures must not have a negative effect on results. Also, the commission agrees with commenters that portable analyzer monitoring represents unnecessary additional cost for sites that do not currently use them for compliance with other rules. The commission believes that for the purposes of a standard permit colorimetric tests (stain tubes) offer a reasonable assurance of compliance. The commission proposes periodic evaluations after engine maintenance. In response to comment, the commission adopts no requirement. The commission agrees with commenters that the majority of engine maintenance has a positive or neutral effect on emissions. The commission proposes a Combustion Device biennial testing requirement. The commission adopts a clarified header, Engines and Turbines. The commission also adopts grammatical changes to the engine and turbine biennial testing language in Table 7 for ease of reading.

In Table 7 stack testing and monitoring of oxidizers claiming higher efficiencies or establishing alternate temperature or residence time requirements, the VOC, benzene, O₂ and possibly H₂S exhaust content must be measured along with the exhaust temperature. Where intermediate, enhanced, or alternate monitoring requires continuous parameter monitoring standard permit averaging times and quality assurance and control checks must be applied. Averaging times of six minutes or less ensure that the dramatic effect of non combustion does not occur. Reasonable temperature accuracy for high temperature monitors has been ± 0.75 percent or ± 10.55555 degrees F for 1,400°F. Oxygen and CO monitoring must be zeroed and spanned daily and comply with EPA performance specifications in 40 CFR Appendix B and F. The standard permit allows for an exemption from monitoring on weekends and plant holidays, and cylinder gas audits may be used in lieu of a relative accuracy test audit. Standard data availability of at least 5 is expected over rolling 12 month periods.

Records of unit parameter adjustments must be maintained because of the effect on emissions. Records of hours of operation, downtime of combustion devices, and engines, as measured by run time meters or other process monitors, are necessary to ensure that equipment is operating properly and corresponds to emission quantifications. Any redirection of vent streams during operational variations must be recorded and must explain associated alternate controls and emission releases to the atmosphere. This is important to ensure that emissions from these alternate operations do not exceed the applicable emission limits.

Tank/process vessel records must be maintained to ensure that the tanks are properly inspected and maintained to reduce and minimize potential increases in emissions due to poor tank condition and non-reflective paint color.

Truck loading records of amount and type of material being loaded must be maintained as well as the type of transfer used. This is important for demonstrating the site outputs and estimating emissions. Tank truck certificates and testing records must be maintained to ensure that loading emissions were estimated appropriately including the proper use of reductions taken based on controls.

Cooling tower and heat exchanger systems records on circulation and solids define potential emissions. Emission estimates of VOC applying uncontrolled factors from AP-42, Compilation of Air Pollutant Emission Factors, are generally accepted to account for losses until process losses are noticed. Emission estimates using controlled factors from AP-42 are generally accepted when the water circulating back to the cooling tower is routinely monitored so heat exchangers leaks can be detected and repaired sooner. The cooling water return to the cooling tower must be monitored for VOC emissions by the method in Appendix P, of the Sampling Procedures Manual or equivalent approved in writing specific to the site to ensure that VOC emissions meet the applicable emission limits when the control factor is assumed. The VOC faulty equipment trigger of 0.08 ppmv in the water are standard in permits and associated with the capability of the Appendix P method and associated AP-42 controlled emission factor in Texas. Particulate emissions from cooling towers are associated with the solids content and drift from the tower. Permit holders are assumed to be regulating and maintaining designed maximum solids content through water blowdowns and makeup water so the heat exchangers and piping do not lose process effectiveness from scale and plugging. Where blowdown is necessary to maintain solids content the record of the weekly total dissolved solids is required. Drift eliminators should be inspected annually to maintain the design control estimated.

MSS records including the source and control of blowdowns and depressurization must be maintained in order to demonstrate that emissions are protective of public health and do not exceed the hourly and annual limitations for the site. There is a potential for a large amount of emissions in a short period of time with these types of events.

Flares and vapor combustors designed like flares, all pilot flames must be continuously monitored by a thermocouple or an infrared monitor to ensure the presence of a flame, which is essential for gas ignition. Any loss in pilot flame must be recorded in order to properly account for resulting uncontrolled emissions.

Thermal oxidizer exhaust temperature and a method of establishing hours of operation are the basic monitored parameters. For higher efficiency design and claim continuous temperature recording and compliance and where claimed oxygen or carbon monoxide concentration must be continuously monitored and recorded when waste gas is directed to it to ensure good combustion/waste gas destruction. Flexibility is allowed when utilizing waste gas for fuel in process combustion devices as noted previously and six minute averages address the dramatic effect (0 percent control) of non-combustion. Quality assurance, quality control, and all necessary maintenance should be recorded.

Some of the records may already be compiled and kept in various formats for other regulatory agencies. The commission is seeking comment and is continuing research on this issue.

Paragraph (k) outlines requirements for establishing site-specific emission limits based on one or more standardized impacts evaluation techniques. For the proposal, the commission had included in paragraph (k)(1) a basic precept for all air permitting emission quantifications, that estimates be based on representative, worst-case operations and planned MSS activities. For the adoption, the commission has moved the expectations for worst-case emission estimations to paragraph (h). In response to comments, the commission notes that the applicant may choose to use various impacts evaluation methods for the same registration, depending on the project and registration's emissions of any particular air contaminant. For example for a project installing a new engine, NO₂ NAAQS compliance may be demonstrated using SCREEN modeling, while SO₂ compliance with NAAQS concentrations may be demonstrated using the impacts tables.

The commission has also added paragraph (k)(1)(A) and (B). For paragraph (k)(1)(A), ambient air standard requirements have been moved from paragraph (b)(6) with grammatical changes. The commission has also added specifics on the relevant distance, consistent with the distance used to establish the limits. For paragraph (k)(1)(B), Effects Screening Level requirements have been moved from paragraph (b)(6) with grammatical changes. The commission has also added specifics on the relevant distances, consistent with the distances used to establish the limits.

Paragraph (k)(2) explains what distance measurements are needed. To alleviate any confusion, it is specifically stated that the distances needed are for each facility or group of facilities is the shortest distance from any emission point to the nearest receptor or nearest property line, depending on whether the compliance demonstration is for an ESL or an ambient air standard. For adoption, the commission has made one small grammatical change. The “and” between state and federal in paragraph (k)(2)(B) has been changed to “or.”

The commission has adopted paragraph (k)(3) to list the exemptions from completing a detailed contaminant review. Adopted paragraph (k)(3)(A) exempts projects with no receptor within 1 mile from any ESL evaluation. Based on comments, the commission has added this exclusion, agreeing that if no receptor could be impacted in close proximity and since the emission caps for speciated VOCs are based on 1 mile distance to receptors, there is nothing gained from performing this impacts evaluation. Adopted paragraph (k)(3)(B) exempts projects with no property boundary within 1 mile from any state or federal ambient air standards evaluation. Based on comments, the commission has added this exclusion, agreeing that if no property line is in close proximity and since the emission caps were set to demonstrate protection of the standards at 1 mile distance to property lines, there is nothing gained from performing this impacts evaluation. For adoption, paragraph (k)(3)(C) has been moved from paragraph (k)(3)(B). Based on proposal comments, paragraph (k)(3)(C) has been clarified to explain that the total quantity of emissions for the project must be less than the listed rates in order for no further demonstration for a contaminant to be required. Using this basis is the most appropriate because this evaluation should account for all sources related to the project which has triggered the standard permit. This evaluation is consistent with the other impact exception criteria. The word “any” is also added to clarify that if any contaminant total emission rates are below the listed rates, the demonstration is not required for that contaminant. This means that demonstration could be required for one particular contaminant, but not for another.

The values used for the exemptions in paragraph (k)(3)(C)(i) - (vii) were developed from the most appropriate and most stringent modeling results in paragraph (m) at the closest distance of 50 feet. If emissions are less than these values, compliance with all ambient air standards and ESLs will be met; therefore, requiring an analysis by applicants would be redundant and unnecessary. To aid in this review, pollutant specific modeling result tables were created from the generic modeling results. For each pollutant, the most stringent of either an ESL or an ambient air standard expressed as a concentration was divided by the generic modeling results, which are in units of ($\mu\text{g}/\text{m}^3$)/(lb/hr) to obtain a table of emission rates (lb/hr). The value for NO_x was based on the less than 1,000 hp engine table, the new hourly NAAQS, and the shortest stack height, or 9 lb/hr. The value for H_2S was based on the fugitive column of paragraph (m), Table 2 at 50 feet and was 0.025 lb/hr. The value for SO_2 was based on the 8 foot height smallest engine type of paragraph (m), Table 5A at 50 feet and was 2 lb/hr. The value for benzene was based on the fugitive column of paragraph (m), Table 2 at 50 feet. Since the annual ESL for benzene is more stringent than the hourly ESL, the commission assumed steady-state releases of benzene and estimated maximum hourly emissions using the annual ESL, resulting in a value of 0.013 lb/hr.

The value for toluene was based on the fugitive column of paragraph (m), Table 2 at 50 feet and is 0.146 lb/hr. The value for xylene was based on the fugitive column of paragraph (m), Table 2 at 50 feet and was 0.08 lb/hr.

Based on the revised modeling, the following paragraph now explains how the adopted values were chosen. The NO_x and SO₂ exemption values are the most stringent emission limitations at a 50-foot distance to property line from an engine smaller than 250 hp with an 8-foot stack; and a conservative 50 percent ratio of NO₂ to NO_x is assumed. The exemption value for H₂S is the most stringent emission limitations at a 50 foot distance to receptor from an engine smaller than 250 hp with an 8-foot stack.

Paragraph (k)(4), which was paragraph (k)(3)(C) in the proposal, discusses what is required for evaluation of emissions. In paragraph (k)(4)(A), the optional method of assuming all VOCs consistent with the most restrictive ESL under worst-case dispersion and closest distance to a receptor has been deleted based on comments stating that this option is too restrictive to be a meaningful tool for a project or registration. NO₂ to NO_x ratios have been updated based on engine testing as provided by companies, vendors, or manufacturers. The typical NO₂ to NO_x ratio from engine sampling commonly seen by the commission ranges from less than 5 percent to 40 percent. The annual NO₂ NAAQS has an EPA-approved modeling default ratio of 0.75. The current 1-hour NO₂ NAAQS has an interim modeling default ratio of 0.75 as well. That means that 75 percent of the NO_x emitted is assumed to be NO₂ and modeled as such. The commission believes using the 0.75 ratio is too conservative for the 1-hour standard given several important factors. First, actual sampling data received in response to comments shows that the percentage of NO_x that is NO₂ immediately prior to release into the atmosphere ranges from 2 to 20 percent with the majority less than 15 percent for 4-stroke rich burn and 4-stroke lean burn engines. This is well below the modeling default ratio of 0.75. Secondly, NO is oxidized to NO₂ in the atmosphere by reaction with other molecules (ozone, etc.). This requires time, but the plume also is being dispersed the farther from the stack it travels. So, while the ratio of NO₂ to total NO_x for a given standard permit of the plume may be slowly increasing to an equilibrium ratio of 0.75, the total NO_x concentration is dropping as distance from the stack increases. The maximum ground level impact of NO₂ occurs where the product of the NO₂/NO_x ratio times the total NO_x concentration is the greatest at any given location. Given how quickly ground level concentrations usually drop as distance increases and the time needed to reach equilibrium, this maximum NO₂ impact tends to be relatively close to the emission point. A previous compressor station study by the commission showed that the NO₂/NO_x ratio appeared to max out at around 14 percent in the area downwind of the studied site where maximum NO_x concentrations were expected. Upon review of this information, the commission has determined it is reasonable to allow a lower NO₂/NO_x ratio. Given the submitted sampling data and previous commission experience, a ratio of 20 percent is appropriate for 4 stroke engines. Several 2- stroke lean burn engines in the submitted data set emitted about 50 percent NO₂ and the commission believes the ratio of 50 percent is appropriate for 2- stroke engines. The commission does not anticipate allowing lower values than these due to the complexity of validating site specific values. Sites wishing to use a lower ratio may have to perform ambient air monitoring for NO₂ at the predicted location of the maximum ground level impact of NO₂.

In paragraph (k)(4)(B), it states that the maximum predicted concentration or rate must not exceed a state or federal ambient air standard or ESL. The scope of the analysis has been moved to paragraph (k)(5). The last sentence of this subparagraph was redundant with the first sentence, and therefore was deleted.

Paragraph (k)(5) discusses what is required for ESL and ambient air standards reviews in paragraph (k)(5)(A) and (B), respectively. Paragraph (k)(5)(A)(i) states that if a project's air contaminant maximum predicted concentrations are equal to or less than 10 percent of the appropriate ESL, no further review is required. Based on the "Modeling and Effects Review Applicability: How to Determine the Scope of Modeling and Effects Review for Air Permits" guidance document last revised in July 2009 by the commission, the commission has added options to evaluate only the emissions from the project, and not all sources within 1/4 mile of the project. This option is based on several comments and this approach is consistent with minor source review permitting procedures which have been followed by the Air Permits Division since 1993. This approach provides a process to protect public health and welfare and effectively manage permitting and agency support staff resources. The thresholds for health effects reviews are consistent with this guidance (10 percent of an ESL). Paragraph (k)(5)(A)(ii) states if the combination of multiple project increases corresponding air contaminant maximum predicted concentrations over any period of time are equal to or less than 25 percent of the appropriate ESL, no further review is required. The commission has established a maximum amount of cumulative increases over time (25 percent) to ensure that emissions "creep" does not occur over multiple projects without a more comprehensive review being performed. Paragraph (k)(5)(A)(iii) states that in all other cases, all facility emissions, regardless of authorization type, located within 1/4 mile of a project requiring registration under this standard permit shall be evaluated. The requirements for additional facilities to be included in the impacts analysis moved from paragraph (b)(6). Clause (k)(5)(B)(i) states that if a project's air contaminant maximum predicted concentrations are equal to or less than the SIL (also known as de minimis impact), no further review is required. Based on recent implementation guidance from EPA regarding the new NO₂ and SO₂ NAAQS, the commission is using the significance impact level (SIL), more commonly known in Texas as de minimis impact level, to allow evaluation of the project only. This option is based on several comments and this approach is consistent with major and minor source review permitting procedures followed by the Air Permits Division. This approach provides a process to protect public health and welfare and effectively manage permitting and agency support staff resources. The current thresholds for ambient air standards reviews are consistent with EPA guidance. This exception is consistent with minor and major preconstruction permit reviews. Paragraph (k)(5)(B)(ii) states that in all other cases, all facility emissions, regardless of authorization type, located within 1/4 mile of a project requiring registration under this standard permit shall be evaluated. The requirements for additional facilities to be included in the impacts analysis moved from paragraph (b)(6).

Finally, in paragraph (k)(6), modified from paragraph (k)(4), the commission adopts three methods for demonstrating protectiveness. The commission has renumbered the paragraph of tables to paragraph (m) due to the inclusion of information on existing, unchanged facilities and projects before the standard permit effective date in adopted paragraph (l). The first method is to use tables developed from generic impacts modeling performed by the commission. Based on comments, the commission has expanded the table distances to just over 1 mile to allow for more flexibility based on actual locations throughout Texas. The commission has also expanded the tables for engines based on more specific and representative dispersion characteristics, and renumbered to Table 5A-F in paragraph (m). The Tables have also been reorganized as follows: Table 2. Generic Modeling Results for Fugitives and Process Vents (no change); Table 3. Generic Modeling Results for Flares; Table 4. Generic Modeling Results for Blowdowns and Gas Pipeline Purging; Table 5A Generic Modeling Results for Engines and Turbines Less than or Equal to 250 horsepower; Table 5B Generic Modeling Results for Engines and Turbines More than 250 hp to Less than or Equal to 500 horsepower; Table 5C Generic Modeling Results for Engines and

Turbines More than 500 hp to Less than or Equal to 1,000 horsepower; Table 5D Generic Modeling Results for Engines and Turbines More than 1000 hp to Less than or Equal to 1,500 horsepower; Table 5E Generic Modeling Results for Engines and Turbines More than 1,500 hp to Less than or Equal to 2,000 horsepower; and Table 5F Generic Modeling Results for Engines and Turbines Greater than 2,000 horsepower. The commission limits the evaluation in paragraph (k) to 5,500 feet based on consideration of distance limits for contiguous properties and operationally related facilities; the highly conservative nature of the assumptions used to develop the model and modeling approach discussed in the impacts analysis; and the commission's intent to establish conservative emission rates and site-wide caps to address the requirements of various air quality permitting programs. In addition, it is the commission's experience that worst-case modeled concentrations from the facilities authorized by this standard permit do not occur under actual operating and meteorological conditions and are not measured at the values predicted at distances beyond 5,500 feet.

Using the generic impacts modeling tables developed by the commission is considered the simplest approach to this evaluation. Based on the variability of equipment and operations, it was determined that emission releases would be grouped for dispersion modeling to predict acceptable off-property impacts. This analysis will be compared to expected emission types and quantities for assessment of protectiveness and compliance with state and federal emission standards from common OGS. The generic approach could also be used to show the appropriate insignificance or acceptability of various operations, providing additional flexibility for OGS seeking authorization under the standard permit. The groups of similar emission releases were chosen based on similar parameters of the release points. The other two methods are screening modeling and refined dispersion modeling.

Paragraph (k)(6)(B) includes a screening alternative based on the use of the SCREEN3 model. The OGS would follow a modeling protocol provided by the commission to conduct a modeling analysis that demonstrated acceptable emissions from the site. The protocol and associated guidance would be included in an oil and gas guidance document available via the agency website and is summarized in this document. The protocol would be followed exactly and there would be no opportunity to modify the protocol on a case-by-case basis. However, the commission could modify the modeling protocol and guidance to resolve technical issues or clarify instructions, or allow the use of other screening models. Since this is a standardized approach, it is appropriate to allow OGS to use these mechanisms to demonstrate protectiveness. The commission contemplates a protocol similar to the one described below.

For control options, the following parameters must be chosen: the regulatory default option must be selected; the flat terrain choice should be used; and rural or urban dispersion options may be used based on the land use in the vicinity of the sources to be permitted. A land use analysis must be conducted to determine the majority land-use type within 3 kilometers (km) of the sources to be permitted. The goal in a land-use analysis is to estimate the percentage of the area within a 3- km radius of the source to be evaluated as either urban or rural. If the land-use designation is clear (about 70 percent or more of the total land-use is either urban or rural), then no further refinement is required and the model should be run with the appropriate land-use designation. If the land-use designation is not clear, the model should be run twice, once with each option and the higher of the two predicted concentrations should be reported.

For source options in the screen model, only point sources, pseudo-point sources, and flares are applicable to represent emission sources. If the emission sources cannot be represented by one of the source types, then this method cannot be used. The point source parameters shall include the following: emission rate in grams per second (g/s); stack height in meters (m); stack inside diameter in meters (m); stack gas exit velocity in meters per second (m/s) or flow rate in cubic feet per minute or meters per second (ft³/min or m³/s); and stack gas temperature in Kelvin (K). For fugitive sources and for any sources that do not release to the atmosphere through standard stacks (such as stacks or vents with rain caps, horizontal releases), use the pseudo-point characterization with the following modeling parameters: stack exit velocity = 0.001 m/s; stack exit diameter = 0.001 m; stack exit temperature = 0 K; and actual release height. Flares shall include: emission rate (g/s); flare stack height; and total heat release rate (cal/s). SCREEN3 assumes an effective stack gas exit velocity (v_s) of 20 m/s and an effective stack gas exit temperature (T_s) of 1273K, and calculates an effective stack diameter based on the heat release rate. Enclosed vapor combustion units should not be modeled with the preceding parameters but instead with stack parameters that reflect the physical characteristics of the unit.

The starting receptor should be located at the shortest distance from the facility/source to the property line. The ending receptor should be far enough away to ensure that the model can predict a GLCmax between the two points. For meteorology, the model default of full meteorology is required, the model default of 10 meters is required for the anemometer height, and the model default of regulatory is required for the mixing height. Downwash is not applicable for the purposes of this modeling demonstration. If downwash is required, then this method cannot be used at this time.

The output shall include: the maximum predicted concentration must be used to compare against the applicable ESL, NAAQS, or state ambient air standard; and the following conversion factors can be used to convert 1-hour concentrations from SCREEN3 to averaging times greater than one-hour: three-hour multiply by 0.9; eight-hour multiply by 0.7; 24-hour multiply by 0.4; quarterly multiply by 0.2; and annual multiply by 0.08. The following steps must be followed when conducting the NAAQS analysis: model all new and modified sources -- the project; compare the maximum predicted concentration from the project to the appropriate *de minimis* level - compliance with the NAAQS is demonstrated if the maximum predicted concentration from the project is less than or equal to the *de minimis* level; a site wide analysis must be conducted for project results than *de minimis*; model the allowable emission rate of all sources on site that emit the regulated pollutant; and add a background concentration to the maximum predicted site- wide concentration and compare the total concentration to the NAAQS. Compliance with the NAAQS is demonstrated if the total concentration is less than or equal to the NAAQS. The following steps must be followed when conducting the analysis to show compliance with the state standards for net ground-level concentrations in 30 TAC Chapter 112 or ESLs: model all new and modified sources -- the project; compare the maximum predicted concentration from the project to the appropriate *de minimis* level - compliance with the state property line standards or ESLs is demonstrated if the maximum predicted concentration from the project is less than or equal to the *de minimis* level; if the maximum predicted concentration is greater than *de minimis*, a site-wide analysis must be conducted; model the allowable emission rate of all sources on site that emit the contaminant. Compliance with the state property line standards and ESL is demonstrated if the maximum predicted site-wide concentration is less than or equal to the state property line standard or ESL.

There are two recommended methods of screening techniques. These are the worst-case stack method and the multiple source method. The worst-case stack method selects the single worst case stack for the site and assumes that all pollutants will be emitted from that point. The worst-case stack method allows all pollutants to be evaluated from a single stack. Use the following equation to determine the worst-case stack: $M = (h_s \sqrt{V T_s})/Q$ where M = a parameter that accounts for the relative influence of stack height, plume rise, and emission rate on concentrations; h_s = the physical stack height in meters; $V = (\pi/4)d^2v_s$ = the stack gas flow rate in cubic meters per second; π = pi; d = inside stack diameter in meters; v_s = stack gas exit velocity in meters per second; T_s = the stack gas exit temperature in K; Q = pollutant emission rate in grams per second. The stack with the lowest value of M is considered to be the worst-case stack. The multiple source method allows each source to be modeled at 1 lb/hr. The unit impact for each source is multiplied by the pollutant specific emission rate to calculate a maximum predicted concentration for each pollutant. The maximum predicted concentration for each source is summed to get a total concentration for each pollutant. This technique works best if the unit impacts and emission rates for each source and each pollutant are loaded into a spreadsheet such as Microsoft EXCEL. Once the modeling exercise is complete the results should be summarized in a modeling report. The modeling report should be sent to the commission and include a compact disk (CD) with all modeling input files, output files, plot plan, and all other files of supporting information used in the modeling demonstration.

Paragraph (k)(4)(C) includes a refined dispersion modeling alternative based on the Industrial Source Complex model. The OGS would follow a modeling protocol provided by the commission to conduct a modeling analysis that demonstrated acceptable emission from the site. The protocol and associated guidance would be included in an oil and gas guidance document available via the agency website. The protocol would be followed exactly and there would be no opportunity to modify the protocol on a case-by-case basis. However, the commission could modify the modeling protocol and guidance to resolve technical issues, clarify instructions, or allow the use of other refined dispersion models. Since this is a standardized approach, it is appropriate to allow OGS to use these mechanisms to demonstrate protectiveness.

The control options used must meet the following: the regulatory default option must be selected; the flat terrain choice should be used; plume depletion options are not allowed; and rural or urban dispersion options may be used based on the land use in the vicinity of the sources to be permitted. A land use analysis must be conducted to determine the majority land-use type within 3 km of the sources to be permitted. The goal in a land-use analysis is to estimate the percentage of the area within a 3-km radius of the source to be evaluated as either urban or rural. If the land-use designation is clear (about 70 percent or more of the total land-use is either urban or rural), then no further refinement is required and the model should be run with the appropriate land-use designation. If the land-use designation is not clear, the model should be run twice, once with each option and the higher of the two predicted concentrations should be reported. The commission contemplates a protocol similar as that described below.

Only point sources, pseudo-point sources, and flares are applicable to represent emission sources. If the emission sources cannot be represented by one of the source types, then this method cannot be used. Point source parameters shall meet the following: emission rate (g/s); stack height (m); stack inside diameter (m); stack gas exit velocity (m/s) or flow rate (ft³/min or m³/s); and stack gas temperature (K). For fugitive sources and for any sources that do not release to the atmosphere through standard stacks (such as stacks or vents with rain caps, horizontal releases), use the pseudo-point characterization with the following modeling parameters: stack exit velocity = 0.001 meter per second; stack exit diameter = 0.001 meter; stack exit temperature = 0 K; and actual release height.

For flares, the following must be included: emission rate (g/s); effective stack exit velocity = 20 meters per second; effective stack exit temperature = 1273 K; actual height of the flare tip; and effective stack exit diameter. The effective stack diameter (D) in meters is calculated using the following equations: $D = \sqrt{10^{-6} q_n}$ and $q_n = q(1 - 0.048\sqrt{MW})$; where: q = gross heat release in cal/sec; q_n = net heat release in cal/sec; and MW = weighted (by volume) average molecular weight of the compound being flared. Enclosed vapor combustion units should not be modeled with the preceding parameters but instead with stack parameters that reflect the physical characteristics of the unit.

The following sets of receptor spacing shall be used to locate the maximum predicted concentration. The maximum predicted concentration should not be located at the edge of the receptor grid. If the maximum predicted concentration occurs within 1,000 meters of the property line, the medium and coarse receptors would not need to be included in the analysis: tight receptors - receptors spaced 25 meters apart extending out to a distance of 300 meters from the property line; fine receptors - receptors spaced 100 meters apart beginning at 300 meters from the property line and extending out to a distance of 1,000 meters from the property line; medium receptors - receptors spaced 500 meters apart beginning at 1,000 meters from the property line and extending out to a distance of 5,000 meters. The Air Dispersion Modeling Team (ADMT) has prepared meteorological data sets for state modeling analyses. These data sets are available for download from the ADMT Internet page. The ADMT prepared meteorological data sets must be used in the modeling analysis and may be found at www.tceq.state.tx.us/permitting/air/modeling/admtmet.html. The required year for short-term modeling is 1988 (1989 for counties using Shreveport data). The actual anemometer height must be used for each airport location. Anemometer heights may be found at www.tceq.state.tx.us/assets/public/permitting/air/memos/anemom96.pdf.

Downwash is not applicable for the purposes of this modeling demonstration. If downwash is required, then this method cannot be used at this time. For the coordinate system: enter receptor locations and source locations into dispersion models in universal transverse mercator (UTM) coordinates, in order to be consistent with on-property emission point locations represented in the Air Permits Division Form PI-1, Table 1(a) available through the commissions WebPages contained in the permit application, plot plan, and other reference material, such as United States Geological Survey topographic maps; UTM coordinates in datum NAD27 or NAD83 must be used. When representing receptor and source locations in UTM coordinates, applicants must make certain that all of the coordinates originated in, or are converted to, the same horizontal datum. Applicable UTM zones in Texas are either 13 (from the west border to 102 degrees longitude), 14 (between 102 and 96 degrees longitude), or 15 (east of 96 degrees longitude to the east border); and coordinate systems based on plant coordinates, applicant-developed coordinate systems, or polar grids will not be accepted.

The output must include the maximum predicted concentration which must be used to compare against the applicable ESL, NAAQS, or state ambient air standard; the use of any other concentration rank other than the maximum (high second high, high sixth high) will not be accepted. The following steps must be followed when conducting the analysis: model all new and modified sources -- the project; compare the maximum predicted concentration from the project to the appropriate *de minimis* level - compliance with the NAAQS is demonstrated if the maximum predicted concentration from the project is less than or equal to the *de minimis* level; a site-wide analysis must be conducted for project results other than *de minimis*; model the allowable emission rate of all sources on site that emit the regulated pollutant; and add a background concentration to the maximum predicted site-wide concentration and compare the total concentration to the NAAQS. Compliance with the NAAQS is demonstrated if the total concentration is less than or equal to the NAAQS.

The following steps must be followed when conducting the analysis to show compliance with the state standards for net ground-level concentrations in 30 TAC Chapter 112 and ESLs: model all new and modified sources -- the project; compare the maximum predicted concentration from the project to the appropriate *de minimis* level - compliance with the state property line standards and ESLs is demonstrated if the maximum predicted concentration from the project is less than or equal to the *de minimis* level; if the maximum predicted concentration is greater than *de minimis*, a site-wide analysis must be conducted; model the allowable emission rate of all sources on site that emit the contaminant; and compliance with the state property line standard and ESL is demonstrated if the maximum predicted site-wide concentration is less than or equal to the state property line standard or ESL. Once the modeling exercise is complete, the results should be summarized in a modeling report. The modeling report should be sent to the commission and include a CD with all modeling input files, plot files, output files, plot plan, and all other files of supporting information used in the modeling demonstration.

Table 1 lists the equations which give the maximum acceptable emissions when using the tables. This equation is similar to $E = L/K$ in §106.262, but with different parameters. For ambient air standards, $E_{max} = P/G$ where E_{max} is the maximum hourly emissions acceptable (lb/hr); P is the appropriate property line standard ($\mu\text{g}/\text{m}^3$); and G is the value from the Generic Emissions Tables at the emission point's release height and distance to property line ($[\mu\text{g}/\text{m}^3]/[\text{lb}/\text{hr}]$). For health effects review, $E_{max} = \text{ESL}/G$ where E_{max} is the maximum acceptable hourly emissions (lb/hr); ESL is the current published effects screening level for the specific air contaminant ($\mu\text{g}/\text{m}^3$); and G is the value from the Generic Emissions Tables at the emission point's release height and distance to property line ($[\mu\text{g}/\text{m}^3]/[\text{lb}/\text{hr}]$).

Most OGS have more than one facility or release point of emissions. To account for this variability, instead of co-locating all sources at the most conservative point of release to establish acceptable emission rates and confirm compliance with the standard permit, OGS may use a weighted fraction method. The five tables predict impacts based on various dispersion characteristics, with greater acceptable emissions from various sources (smallest to largest): fugitives, blowdowns, process vents, combustion devices, and flares. Since many of these facilities emit air contaminants simultaneously, the corresponding contribution of each release must be considered to ensure acceptable emissions. Therefore, acceptable emission limits are determined using a weighed ratio. For simultaneously emitting sources, the weighted fraction method with the above equation may be used for any combination of sources emitting the same air contaminant: $E_{max} (\text{lb}/\text{hr}) = (\text{WR EPN } 1) (P / G \text{ EPN } 1) + (\text{WR EPN } 2) (P / G \text{ EPN } 2) + (\text{WR EPN } 3) (P / G \text{ EPN } 3) + \dots$ or $E_{max} (\text{lb}/\text{hr}) = (\text{WR EPN } 1) (\text{ESL} / G \text{ EPN } 1) + (\text{WR EPN } 2) (\text{ESL} / G \text{ EPN } 2) + (\text{WR EPN } 3) (\text{ESL} / G \text{ EPN } 3) + \dots$

With minor adjustments, this same equation can be used for annual impacts evaluation. Standard practice, as published in the TCEQ Modeling Guidance Document, is to multiply the hourly impact concentration by 0.08 to establish a conservative annual impact concentration. Thus, the weighted fraction equations would be: $E_{max} (\text{tpy}) = (8760/2000) \{ (\text{WR EPN } 1) (P / [0.08 * G \text{ EPN } 1]) + (\text{WR EPN } 2) (P / [0.08 * G \text{ EPN } 2]) + (\text{WR EPN } 3) (P / [0.08 * G \text{ EPN } 3]) + \dots \}$ or $E_{max} (\text{tpy}) = (8760/2000) \{ (\text{WR EPN } 1) (\text{ESL} / [0.08 * G \text{ EPN } 1]) + (\text{WR EPN } 2) (\text{ESL} / [0.08 * G \text{ EPN } 2]) + \dots \}$ where $E_{max} (\text{lb}/\text{hr}) =$ maximum hourly emissions acceptable (lb/hr); $E_{max} (\text{tpy}) =$ maximum tons per year emissions acceptable (tpy); $\text{WR EPN}(x) =$ Emissions of each EPN divided by the sum of total emissions for all EPNs that emit that pollutant or ($\text{E EPN } x / E_{total}$); P = short term or annual (as appropriate) property line standard ($\mu\text{g}/\text{m}^3$); ESL = current published short term or annual (as appropriate) effects screening level for the specific air contaminant ($\mu\text{g}/\text{m}^3$); and G = value from the Generic Emissions Tables at the emission point's release height and distance to property line ($[\mu\text{g}/\text{m}^3]/[\text{lb}/\text{hr}]$).

Based on modeling guidance, a pressurized vessel and other facilities which release emissions in an undirected manner and short duration such as pressurized separators, sulfur treating vessels, piping, and tanks, etc. can be treated as a fugitive released emission covered in this standard permit. These emissions should be reviewed under the first column for “fugitive, loading, and tanks” in Table 2. For federal purposes, this definition of “fugitive” is not appropriate since these emissions are potentially collectable and capable of being routed to a control. This difference in accounting for these emissions for federal purposes could be significant in a few application situations near significant and major increase levels in PSD applications, since for named major sources fugitive emissions count in PSD evaluation of the emissions. For other federal sources, fugitive emissions are not counted in determination of a significant or major emission increase.

The cumulative impacts from any given OGS as defined must be considered for protectiveness. To provide flexibility, applicants may use the weight fraction method of proportioning impacts in the same way as §§106.261 and 106.262 currently use to proportion impacts from different sources at different distances. The authorizations contain several tables applicable to the type sources located at the site. This will enable an applicant to compute their emission limits for the applicable air contaminants from those sources. Each table will allow an applicant to either meet specific emission limits, or compute the specific emission limit for that type source. These tables can be used assuming 100 percent of the specific emissions are at a worst-case point (very conservative). They may also be used to compute the specific emission limit for each emission point (may involve different distances, heights, and type tables) by use of the weight fraction method, which will allow for consideration of multiple, similarly emitting sources operating simultaneously at an OGS. The most conservative approach using the worst-case source calculated from each table will result in the maximum impact allowed for protectiveness from that source without regard to other sources emitting the same compound at the same time. Using the weight fraction approach, emission limits can be established for all other type equipment emitting the same compound at the same time. If the OGSs estimated emission rates using either method are less than or equal to the calculated emission rate limit as determined from the tables, the emissions are acceptable and can be authorized.

Paragraph (k)(4)(B) includes a screening alternative based on the use of the SCREEN3 model. The OGS would follow a modeling protocol provided by the commission to conduct a modeling analysis that demonstrated acceptable emissions from the site. The protocol and associated guidance would be included in an oil and gas guidance document available via the agency website and is summarized in this document. The protocol would be followed exactly and there would be no opportunity to modify the protocol on a case-by-case basis. However, the commission could modify the modeling protocol and guidance to resolve technical issues or clarify instructions, or allow the use of other screening models. Since this is a standardized approach, it is appropriate to allow OGS to use these mechanisms to demonstrate protectiveness. The commission considers a protocol similar to as described below.

For control options, the following parameters must be chosen: the regulatory default option must be selected; the flat terrain choice should be used; and rural or urban dispersion options may be used based on the land use in the vicinity of the sources to be permitted. A land use analysis must be conducted to determine the majority land-use type within 3 kilometers (km) of the sources to be permitted. The goal in a land-use analysis is to estimate the percentage of the area within a 3-km radius of the source to be evaluated as either urban or rural. If the land-use designation is clear (about 70 percent or more of the total land-use is either urban or rural), then no further refinement is required and the model should be run with the appropriate land-use designation. If the land-use designation is not clear, the model should be run twice, once with each option and the higher of the two predicted concentrations should be reported.

For source options in the screen model, only point sources, pseudo-point sources, and flares are applicable to represent emission sources. If the emission sources cannot be represented by one of the source types, then this method cannot be used. The point source parameters shall include the following: emission rate (g/s); stack height (m); stack inside diameter (m); stack gas exit velocity (m/s) or flow rate (ft³/min or m³/s); and stack gas temperature (K). For fugitive sources and for any sources that do not release to the atmosphere through standard stacks (such as stacks or vents with rain caps, horizontal releases), use the pseudo-point characterization with the following modeling parameters: stack exit velocity = 0.001 meter per second; stack exit diameter = 0.001 meter; stack exit temperature = 0 Kelvin; and actual release height. Flares shall include: emission rate (g/s); flare stack height; and total heat release rate (cal/s). SCREEN3 assumes an effective stack gas exit velocity (v_s) of 20 m/s and an effective stack gas exit temperature (T_s) of 1273K, and calculates an effective stack diameter based on the heat release rate. Enclosed vapor combustion units should not be modeled with the preceding parameters but instead with stack parameters that reflect the physical characteristics of the unit.

The starting receptor should be located at the shortest distance from the facility/source to the property line. The ending receptor should be far enough away to ensure that the model can predict a GLCmax between the two points. For meteorology, the model default of full meteorology is required, the model default of 10 meters is required for the anemometer height, and the model default of regulatory is required for the mixing height. Downwash is not applicable for the purposes of this modeling demonstration. If downwash is required, then this method cannot be used. The output shall include: the maximum predicted concentration must be used to compare against the applicable ESL, NAAQS, or state ambient air standard; and the following conversion factors can be used to convert 1-hour concentrations from SCREEN3 to averaging times greater than 1-hour: 3-hour multiply by 0.9; 8-hour multiply by 0.7; 24-hour multiply by 0.4; quarterly multiply by 0.2; and annual multiply by 0.08. The following steps must be followed when conducting the NAAQS analysis: model all new and modified sources, or the project; compare the maximum predicted concentration from the project to the appropriate de minimis level - compliance with the NAAQS is demonstrated if the maximum predicted concentration from the project is less than or equal to the de minimis level; a site wide analysis must be conducted for project results than de minimis; model the allowable emission rate of all sources on site that emit the regulated pollutant; and add a background concentration to the maximum predicted site wide concentration and compare the total concentration to the NAAQS. Compliance with the NAAQS is demonstrated if the total concentration is less than or equal to the NAAQS. The following steps must be followed when conducting the analysis to show compliance with the state standards for net ground-level concentrations in 30 TAC Chapter 112: model all new and modified sources the project; compare the maximum predicted concentration from the project to the appropriate de minimis level - compliance with the state property line standards is demonstrated if the maximum predicted concentration from the project is less than or equal to the de minimis level; if the maximum predicted concentration is greater than de minimis, a site wide analysis must be conducted; model the allowable emission rate of all sources on site that emit the regulated pollutant; and compliance with the state property line standard is demonstrated if the maximum predicted site-wide concentration is less than or equal to the state property line standard.

There are two recommended methods of screening techniques. These are the worst-case stack method and the multiple source method. The worst-case stack method selects the single worst case stack for the site and assumes that all pollutants will be emitted from that point. The worst-case stack method allows all pollutants to be evaluated from a single stack. Use the following equation to determine the worst-case stack: $M = (h_s V T_s)/Q$ where M = a parameter that accounts for the relative influence of stack height, plume rise, and emission rate on concentrations; h_s = the physical stack height in meters; $V = (\pi/4)d^2v_s$ = the stack gas flow rate in cubic meters per second; π = pi; d = inside stack diameter in meters; v_s = stack gas exit velocity in meters per second; T_s = the stack gas exit temperature in Kelvin; Q = pollutant emission rate in grams per second. The stack with the lowest value of M is considered to be the worst-case stack. The multiple source method allows each source to be modeled at 1 lb/hr. The unit impact for each source is multiplied by the pollutant specific emission rate to calculate a maximum predicted concentration for each pollutant. The maximum predicted concentration for each source is summed to get a total concentration for each pollutant. This technique works best if the unit impacts and emission rates for each source and each pollutant are loaded into a spreadsheet such as Microsoft EXCEL. Once the modeling exercise is complete the results should be summarized in a modeling report. The modeling report should be sent to the TCEQ and include a compact disk (CD) with all modeling input files, output files, plot plan, and all other files of supporting information used in the modeling demonstration.

Paragraph (k)(4)(C) includes a refined dispersion modeling alternative based on the Industrial Source Complex model. The OGS would follow a modeling protocol provided by the commission to conduct a modeling analysis that demonstrated acceptable emission from the site. The protocol and associated guidance would be included in an oil and gas guidance document available via the agency website. The protocol would be followed exactly and there would be no opportunity to modify the protocol on a case-by-case basis. However, the commission could modify the modeling protocol and guidance to resolve technical issues, clarify instructions, or allow the use of other refined dispersion models. Since this is a standardized approach, it is appropriate to allow OGS to use these mechanisms to demonstrate protectiveness.

The preliminary protocol follows:

The control options used must meet the following: the regulatory default option must be selected; the flat terrain choice should be used; plume depletion options are not allowed; and rural or urban dispersion options may be used based on the land use in the vicinity of the sources to be permitted. A land use analysis must be conducted to determine the majority land-use type within 3-km of the sources to be permitted. The goal in a land-use analysis is to estimate the percentage of the area within a 3-km radius of the source to be evaluated as either urban or rural. If the land use designation is clear (about 70 percent or more of the total land-use is either urban or rural), then no further refinement is required and the model should be run with the appropriate land-use designation. If the land-use designation is not clear, the model should be run twice, once with each option and the higher of the two predicted concentrations should be reported. The commission contemplates a protocol similar as that described below.

Only point sources, pseudo-point sources, and flares are applicable to represent emission sources. If the emission sources cannot be represented by one of the source types, then this method cannot be used. Point source parameters shall meet the following: emission rate (g/s); stack height (m); stack inside diameter (m); stack gas exit velocity (m/s) or flow rate (ft³/min or m³/s); and stack gas temperature (K).

For fugitive sources and for any sources that do not release to the atmosphere through standard stacks (such as stacks or vents with rain caps, horizontal releases), use the pseudo-point characterization with the following modeling parameters: stack exit velocity = 0.001 meter per second; stack exit diameter = 0.001 meter; stack exit temperature = 0 Kelvin; and actual release height. For flares, the following must be included: emission rate (g/s); effective stack exit velocity = 20 meters per second; effective stack exit temperature = 1273 Kelvin; actual height of the flare tip; and effective stack exit diameter. The effective stack diameter (D) in meters is calculated using the following equations: $D = \sqrt{10^{-6} q_n}$ and $q_n = q(1 - 0.048\sqrt{MW})$; where: q = gross heat release in cal/sec; q_n = net heat release in cal/sec; and MW = weighted (by volume) average molecular weight of the compound being flared. Enclosed vapor combustion units should not be modeled with the preceding parameters but instead with stack parameters that reflect the physical characteristics of the unit.

The following sets of receptor spacing shall be used to locate the maximum predicted concentration. The maximum predicted concentration should not be located at the edge of the receptor grid. If the maximum predicted concentration occurs within 1,000 meters of the property line, the medium and coarse receptors would not need to be included in the analysis: tight receptors - receptors spaced 25 meters apart extending out to a distance of 300 meters from the property line; fine receptors - receptors spaced 100 meters apart beginning at 300 meters from the property line and extending out to a distance of 1,000 meters from the property line; medium receptors - receptors spaced 500 meters apart beginning at 1,000 meters from the property line and extending out to a distance of extending out to a distance of 5,000 meters. The Air Dispersion Modeling Team (ADMT) has prepared meteorological data sets for state modeling analyses. These data sets are available for download from the ADMT Internet page. The ADMT prepared meteorological data sets must be used in the modeling analysis and may be found at <http://www.tceq.state.tx.us/permitting/air/modeling/admtmet.html>. The required year for short term modeling is 1988 (1989 for counties using Shreveport data). The actual anemometer height must be used for each airport location. Anemometer heights may be found at <http://www.tceq.state.tx.us/assets/public/permitting/air/memos/anemom96.pdf>.

Downwash is not applicable for the purposes of this modeling demonstration. If downwash is required, then this method cannot be used. For the coordinate system: enter receptor locations and source locations into dispersion models in universal transverse mercator (UTM) coordinates, in order to be consistent with on-property emission point locations represented in the Table 1(a) contained in the permit application, plot plan, and other reference material, such as United States Geological Survey topographic maps; UTM coordinates in datum NAD27 or NAD83 must be used. When representing receptor and source locations in UTM coordinates, applicants must make certain that all of the coordinates originated in, or are converted to, the same horizontal datum. Applicable UTM zones in Texas are either 13 (from the west border to 102 degrees longitude), 14 (between 102 and 96 degrees longitude), or 15 (east of 96 degrees longitude to the east border); and coordinate systems based on plant coordinates, applicant-developed coordinate systems, or polar grids will not be accepted.

The output must include: the maximum predicted concentration must be used to compare against the applicable ESL, NAAQS, or state ambient air standard; and the use of any other concentration rank (high second high, high sixth high) will not be accepted. The following steps must be followed when conducting the analysis: model all new and modified sources -- the project; compare the maximum predicted concentration from the project to the appropriate de minimis level - compliance with the NAAQS is demonstrated if the maximum predicted concentration

from the project is less than or equal to the de minimis level; a site-wide analysis must be conducted for project results other than de minimis; model the allowable emission rate of all sources on site that emit the regulated pollutant; and add a background concentration to the maximum predicted site wide concentration and compare the total concentration to the NAAQS. Compliance with the NAAQS is demonstrated if the total concentration is less than or equal to the NAAQS. The following steps must be followed when conducting the analysis to show compliance with the state standards for net ground-level concentrations in 30 TAC Chapter 112: model all new and modified sources the project; compare the maximum predicted concentration from the project to the appropriate de minimis level - compliance with the state property line standards is demonstrated if the maximum predicted concentration from the project is less than or equal to the de minimis level; if the maximum predicted concentration is greater than de minimis, a site wide analysis must be conducted; model the allowable emission rate of all sources on site that emit the regulated pollutant; and compliance with the state property line standard is demonstrated if the maximum predicted site-wide concentration is less than or equal to the state property line standard. Once the modeling exercise is complete, the results should be summarized in a modeling report. The modeling report should be sent to the TCEQ and include a CD with all modeling input files, plot files, output files, plot plan, and all other files of supporting information used in the modeling demonstration.

Paragraph (l) is adopted to cover all counties of the state outside of the Barnett Shale region and any unchanged, existing facility throughout the state including the Barnett Shale region. It simply states that the requirements in 116.620 are applicable to existing unchanged facilities and new or changing facilities as specified in paragraph (a)(1). Since the changes to this standard permit are going to affect oil and gas operations in the state, this subsection will cover all OGS constructed in the state starting with the effective date of section, until the applicability date of subsection (a)-(k) for the Barnett Shale Region on April 1, 2011. This paragraph will continue to be the authorization mechanism for facilities that are unchanged, but at a site which has undergone new or modified construction on some facilities, or completes a renewal after 2016.

Paragraph (m) contains all the Tables associated with the standard permit.

- Table 1 Emission Impact Tables Limits and Descriptions;
- Table 2 Generic Modeling Results for Fugitives & Process Vents;
- Table 3 Generic Modeling Results for Flares and Thermal Destruction Devices
- Table 4 Generic Modeling Results for Blowdowns, Purging, and Pigging
- Table 5A Generic Modeling Results for Engines Less Than or Equal to 250 hp
- Table 5B Generic Modeling Results for Engines Greater Than 250 hp to Less Than or Equal to 500 hp
- Table 5C Generic Modeling Results for Engines Greater Than 500 hp to Less Than or Equal to 1000 hp
- Table 5D Generic Modeling Results for Engines Greater Than 1000 hp to Less Than or Equal to 1500 hp
- Table 5E Generic Modeling Results for Engines Greater Than 1500 hp to Less Than or Equal to 2000 hp
- Table 5F Generic Modeling Results for Engines Greater Than 2000 hp
- Table 6 Engine and Turbine Emission and Operational Standards
- Table 7 Sampling and Demonstrations of Compliance;
- Table 8 Monitoring and Records Demonstrations;
- Table 9 Fugitive Component Leak Detection and Repair (LDAR) Control Program
- Table 10 Fugitive Component LDAR BACT Table;
- Table 11 Best Available Control Technology (BACT) Requirements; and

IX. REGULATORY REVIEWS

A. Final Regulatory Impact Analysis Determination

The commission reviewed the rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225 and determined that the rules do not meet the definition of a “major environmental rule.” Texas Government Code, §2001.0225 states that a “major environmental rule” is, “a rule the specific intent of which is to protect the environment or reduce risks to public health from environmental exposure and that may adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state.” While the purpose of this rulemaking is to increase protection of the environment and reduce risk to public health, it is not expected that this rulemaking will adversely affect in a material way the economy, a sector of the economy, productivity, jobs, the environment, or the public health and safety of the state or a sector of the state.

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

The specific intent of the rulemaking is to replace the current requirements of §116.620 and implement a new set of requirements for the standard permit. The new requirements provide an updated, comprehensive, and protective authorization for many common oil and gas facilities in Texas. The standard permit includes operating specifications and emissions limitations for typical equipment (facilities) during normal operation, which includes production and planned MSS. Also, consideration of current emission quantification methods, capture and recovery devices and control equipment will be part of the revised authorizations. The standard permit specifically addresses the appropriateness of multiple authorizations at one site and would reference the many new federal standards which have been promulgated by the EPA, as well as include revised criteria for registration and changes at existing, authorized sites.

Increase in Operating Costs

If currently authorized sites are modified or if new facilities are constructed, various operational costs could be incurred if the required controls are not already in place.

Sites with fugitive components would have to be inspected and repaired to reduce fugitive emissions. Inspecting and repairing equipment with fugitive emissions is estimated to cost about \$1.25 per connection. A site with 20 to 25 connections could see monitoring costs for fugitive emissions range from \$25 to \$31 per year if this type of monitoring is not already taking place. Larger sites could have 1,000 or more connections, and the cost of monitoring fugitive emissions could exceed \$1,250 each year. The cost of monitoring fugitive emissions will vary from site to site depending on the number of connections, activity at the site, and the configuration of the site.

The new standard permit requires the sampling of gas streams with a cost of \$400 to \$1,200 per sample. Sites may require 1 to 6 samples yearly depending on the facilities installed. This gives a potential cost range of \$400 to \$7,200. The new standard permit would also require that glycol dehydrator regenerator vents be controlled at a minimum efficiency of 80 percent by weight. This would be achieved by routing emissions to a vapor recovery system, the unit reboiler, or to another appropriate control device. While the cost of a typical vapor recovery system ranges from \$30,000 to \$100,000, the cost associated with the installation and operation of a vapor recovery system would eventually be offset through recovery of marketable product. The commission further estimates that the cost for new controls or procedures will apply to about 100,000 of the potentially affected oil and gas sites. This estimate is based on facilities having emissions of volatile organic compound below 5 tpy and sulfur compounds below 0.1 tpy. Those facilities not affected by new control requirements are only responsible for notification to the executive director. Other appropriate control devices may include flares. Unfortunately, determining the cost of a flare in regards to this evaluation is presumptuous because the cost of a flare is highly dependent on the size and throughput of a site.

The new standard permit requires that the emissions from some process units now be controlled. This would typically be accomplished with a flare. The capital cost for installation of a flare will be about \$10,000 to \$20,000 for a typical oil and gas site with operating costs mainly due to the cost of addition of natural gas fuel. Larger sites may require larger flares, but these are generally installed currently. There may be sites that prefer or need to use thermal oxidizers or vapor combustors and these units would typically cost more than a flare, but use would be driven by the need to meet impact limitations and not as a mandatory control requirement. Where enhanced control or monitoring is chosen monitoring/sampling ports are required at a cost of about \$2,000. Testing costs are expected to be between \$10,000 to \$20,000 dollars for the pollutants of concern.

The only mandatory monitoring on flares is pilot flame monitoring. A continuous temperature monitor would cost about \$1,500. Operation of a continuous temperature monitor will cost up to about \$200 per year

Under the new standard permit monitoring records of glycol dehydrators includes: measurement of flash tank temperature and pressure; any reboiler stripping gas flow rate; and the condenser outlet gas temperature. A temperature measuring device (thermocouple) monitor will not significantly increase cost. A continuous temperature monitor would cost about \$1,500. Operation of a continuous temperature monitor will cost up to about \$200 per year. Flow monitors and pressure gauges can typically cost \$2,000 and \$500, respectively. The operational cost of these units is about less than \$200 a year. The new standard permit has emission limits for NO_x and CO for boilers, reboilers, heater-treaters, and process heaters, less than 40 MMBtu/hr firing rate. The emission limits are already commonly achieved and will not be expected to increase costs.

The new standard permit has emission limits for NO_x and CO for boilers, reboilers, heater-treaters, and process heaters, equal to or greater than 40 MMBtu/hr firing rate. Boilers, reboilers, heater-treaters, and process heaters, equal to or greater than 40 MMBtu/hr firing rate will not be expected at a typical OGS. Additionally, the emissions limits are currently required in the Air Quality Standard Permit for Boilers.

The new standard permit requires additional records requirements. The commission would not be able to assess additional costs, if any, due to additional records requirements, as some companies already maintain such records, some of the records are already required by other government agencies (such as the Texas Railroad Commission), and some of the records are needed for acceptable business practices.

Under the requirements of this new standard permit compressor engines may require an upgrade to their emissions control catalyst system at a cost of about \$6 per horse power. Installation of a full catalyst system would cost about \$28 per horse power. The resulting total cost, based on engines typically found at oil and gas sites is \$50,000 to \$100,000 per engine.

Engines will have to do a quarterly photo ionization detector (PID) test which is about \$1000 per test, due to the SIP engines in DFW already required to do this test since 2007.

B. Taking Impact Assessment

The commission completed a takings impact assessment for this rulemaking action under Texas Government Code, §2007.043. The specific intent of the rulemaking is to repeal the current requirements of §106.352 and implement a new set of requirements for the PBR. The repeal of this PBR and the issuance of the new PBR do not affect private property in a manner that restricts or limits an owner's right to the property that would otherwise exist in the absence of a governmental action. This rulemaking will not revoke the authorizations of those facilities that are authorized under the previous §106.352. The new PBR requirements would only apply to new or modified facilities. Consequently, this rulemaking action does not meet the definition of a takings under Texas Government Code, §2007.002(5).

C. Consistency with the Coastal Management Program

The commission reviewed the rulemaking and found it is identified in the Coastal Coordination Act Implementation Rules, 31 TAC §505.11(b)(2), relating to rules subject to the Coastal Management Program, and will, therefore, require that goals and policies of the Texas Coastal Management Program (CMP) be considered during the rulemaking process. The commission reviewed this rulemaking for consistency with the CMP goals and policies in accordance with the regulations of the Coastal Coordination Council and determined that the amendments are consistent with CMP goals and policies. The CMP goal applicable to this rulemaking action is the goal to protect, preserve, and enhance the diversity, quality, quantity, functions, and values of coastal natural resource areas (31 TAC §501.12(1)). No new sources of air contaminants will be authorized and the revisions will maintain the same level of emissions control as previous rules. The CMP policy applicable to this rulemaking action is the policy that the commission's rules comply with federal regulations in 40 CFR, to protect and enhance air quality in the coastal areas (31 TAC §501.32). This rulemaking action complies with 40 CFR Part 51, Requirements for Preparation, Adoption, and Submittal of Implementation Plans. Therefore, in accordance with 31 TAC §505.22(e), the commission affirms that this rulemaking action is consistent with CMP goals and policies.

D. Effect on Sites Subject to the Federal Operating Permits Program

The amended PBR and standard permit are applicable requirements under 30 TAC Chapter 122, Federal Operating Permits Program. Upon the effective date of this rulemaking and standard permit issuance, owners or operators subject to the Federal Operating Permit Program that modify any NSR authorized sources at their sites will be subject to the amended requirements of these sections. Currently, an OGS may be authorized by PBR, standard permit, permits, or a combination of these authorizations. This PBR and standard permit were developed to provide an updated, comprehensive and protective authorization for common OGS in Texas. The PBR and standard permit address the appropriateness of multiple authorizations at one contiguous property. One of the limitations of the PBR and standard permit only allows OGS which do not require federal preconstruction authorization under PSD or NNSR. However, new and existing OGS may be subject to the Title V federal operating permit program and must obtain a SOP or a GOP. Based on recent regulatory changes required by EPA and 40 CFR Part 70, a GOP can only be used by sites authorized under PBR or standard permit. If a major site subject to Title V does not qualify for a PBR or standard permit, it must obtain a SOP (submittal deadline December 2008), thus the urgency to pursue these changes and minimize additional, unnecessary paperwork. The commission's intent is to allow for time after the PBR and standard permit are adopted and issued for OGS to update or apply for the PBR or standard permit, before the December 2008 GOP revision or SOP application deadlines.

E. Public Comment

A public hearing was held in Austin on September 14, 2010. Two-hundred-twenty-two commenter's submitted comments during the public comment period which closed on October 1, 2010.

The commenter's included the following: Representative Lon Burnam, Representative James Keffer, Senator Wendy Davis, Senator Robert Nichols, Senator Kel Seliger, Representative Warren Chism, Representative Wayne Christian, Representative Tom Craddick, Representative Kelly Hancock, Representative Rick Hardcastle, Representative Ken Legler, Representative Randy Weber, City of Fort Worth, Akzo Noble, Anadarko Petroleum Corporation (Anadarko), Argyle-Bartonville Communities Alliance (ABCA), Bart May Trucking, British Petroleum America Production Company (BP), Bridgeport Chamber of Commerce, Christian and White Properties, Cirrus Environmental Corporation (Cirrus), ConocoPhillips, Devon Energy Corporation (Devon), Environmental Defense Fund (EDF), El Paso Corporation (El Paso), EnCana Oil and Gas USA Inc. (Encana), United States Environmental Protection Agency, Region 6 (EPA), Energy Transfer Company (ETC), ERM, ExTerran, ExxonMobil Production (ExxonMobil), Fasken Oil and Ranch, Ltd. (Fasken), Fort Worth Crushed Stone, LLC, Fountain Quail Water Management (Ft Quail), Gas Processors Association (GPA), Harris County Public Health and Environmental Services (HCPHES), Hy-Bon, Jerry Lang Combustion Consulting (JLCC), Jones-Blair Paint Co. (JBP), Kinder Morgan, Inc. (Kinder Morgan), Lone Star Chapter of the Sierra Club (Sierra Club), M.E. Operating and Services, Inc., Markwest Energy Partners, Noble Energy Inc. (Noble), Nord On Corporation, NorTex, Old Town Neighborhood Association, Parrish Field Services, Permian Basin Petroleum Association (PBPA), Pioneer Natural Resources USA, Inc. (Pioneer), P_S^TORD OPS^T Corporation, Shell Global Solutions (Shell), Shell Exploration & Production Company (SWEPI), Texas

Alliance of Energy Producers (TAEP), Targa Resources Partners LP (Targa), Texas Pipeline Association (TPA), Texans for Responsible and Accountable Energy Development (TRAED), Texas Oil and Gas Association (TXOGA), Earthworks Texas Oil and Gas Accountability Project, Texas Independent Producers and Royalty Owners Association (TIPRO), Texas Pipeline Association (TPA), Mayor Calvin Tillman of DISH, Weisman Engineering and 124 various individuals.