APPENDIX D

SPECIFIED OIL AND GAS WELL ACTIVITIES EMISSIONS INVENTORY UPDATE

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Specified Oil & Gas Well Activities Emissions Inventory Update

FINAL REPORT

Prepared for:

Texas Commission on Environmental Quality

Air Quality Division

Prepared by:

Eastern Research Group, Inc.

August 1, 2014

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FINAL REPORT

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List of Acronyms

Acronym	Definition
AACOG	Alamo Area Council of Governments
AP-42	U.S. EPA's Compilation of Air Pollutant Emission Factors
API	American Petroleum Institute
bbl	Barrel
BPA	Beaumont-Port Arthur
BTEX	Benzene, Toluene, Ethylbenzene, Xylene
CenSARA	Central States Air Resource Agencies
CO	Carbon Monoxide
CO_2	Carbon Dioxide
EDF	Environmental Defense Fund
EPA	U.S. Environmental Protection Agency
ERG	Eastern Research Group, Inc.
ENVIRON	Environ International Corporation
HGB	Houston-Galveston-Brazoria
lbs	Pounds
MMscf	Million standard cubic feet
NO_x	Oxides of Nitrogen
NSPS	New Source Performance Standard
PM_{10}	Particulate Matter less than10 microns in aerodynamic diameter
PTE	Potential to Emit
ppm	Parts per million
psig	Pounds per square inch gauge
RRC	Railroad Commission of Texas
scf	Standard cubic feet
SO_2	Sulfur Dioxide
TCEQ	Texas Commission on Environmental Quality
TCAT	Texas Center for Applied Technology
TERP	Texas Emissions Reduction Plan
tpy	Tons per year
VOC	Volatile Organic Compound
UBD	Under-balanced drilling
URS	URS Corporation

Executive Summary

Eastern Research Group, Inc. (ERG) is currently under contract with the Texas Commission on Environmental Quality (TCEQ) under Work Order No. 582-11-99776-FY14-26 to provide nonpoint area source oil and gas emissions inventory estimates for mud degassing activities and hydraulic pump engines used at well drilling sites in Texas. ERG also determined the effects of the provisions of the recently revised New Source Performance Standards (NSPS) Subpart OOOO (Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution) on the 2013 emissions inventory estimates. This report describes ERG's findings relative to survey efforts undertaken to collect information on mud degassing activities and the use of hydraulic pump engines in the eight oil and gas basins found in Texas, an analysis of available mud degassing and hydraulic pump engine emission factor data, and an examination of the effects on emissions from the equipment located at upstream oil and gas sources as the requirements of Subpart OOOO are implemented.

Drilling mud is a blend of water, oil, or synthetic fluids, special clays, and other additives. Mud is used during drilling to cool and lubricate the drill bit, remove cuttings to the surface, and control pressure in the wellbore. As drilling proceeds through gas-bearing formations, gas becomes entrained in the drilling mud. After the mud comes to the surface, the entrained gas is released, resulting in volatile organic compound (VOC) and methane emissions.

Hydraulic pump engines are used during well completions to inject mixtures of water, proppants, and other additives at high pressure into petroleum-bearing rock formations to create fissures in the rock. The resulting fissures increase the conductivity of the source rock, increasing the flow rate of petroleum liquids and gas to the wellbore. This technique improves hydrocarbon recovery rates in petroleum-bearing formations that would otherwise be unproductive. The engines are typically diesel-fired engines and are a source of nitrogen oxides (NO_x), carbon monoxide (CO), VOC, and particulate matter (PM) emissions. These emissions typically occur only once during the completion of a well, but are significant in magnitude.

NSPS Subpart OOOO requires operators of certain equipment at upstream oil and gas production sites to control emissions from that equipment beginning in October 2012. These requirements only apply to equipment newly constructed or modified after August 23, 2011. As new wells are completed each year to replace older, non-productive wells, the requirements of Subpart OOOO will apply to an increasing percentage of the wells in Texas over time. Total emissions from the classes of affected equipment will continue to decrease over time as more equipment becomes subject to Subpart OOOO control requirements.

ERG recommends that the TCEQ calculate emissions from mud degassing activities during well drilling using county-level well spud data and the emission factor data obtained under this study. ERG recommends that the TCEQ calculate emissions from hydraulic pump engines based on the county-level horizontal well completion data and the activity and emission factor data obtained under this study. ERG recommends that the TCEQ calculate emissions from Subpart OOOO affected facilities based on county-level data on the number of new well completions since October 2012, Subpart OOOO emission standards, and the emission factors developed in this and previous studies.

1. Introduction

Eastern Research Group, Inc. (ERG) is currently under contract with the Texas Commission on Environmental Quality (TCEQ) under Work Order No. 582-11-99776-FY14-26 to provide updates to TCEQ's nonpoint area source oil and gas emissions inventory estimates. Specifically under this effort, ERG evaluated activity and emissions data needed to characterize typical emissions from hydraulic pump engines and mud degassing equipment located at upstream oil and gas production sites in Texas. Information relative to this analysis was obtained through a survey of oil and gas producers operating in Texas, as well as a comprehensive literature review and interviews with industry experts familiar with the operating characteristics and any ongoing studies for these processes.

In addition, ERG evaluated the effects of the provisions of the recently revised New Source Performance Standards (NSPS) Subpart OOOO (Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution) on the inventory estimates. The results of these analyses were then used to update TCEQ's nonpoint area source oil and gas emissions inventory calculator.

Purpose of This Study

The purpose of this study is to develop and refine the methodologies and characterization factors needed to generate emission estimates from hydraulic pump engines and mud degassing activities at oil and gas wells across Texas, as well as to evaluate and incorporate controls required under NSPS Subpart OOOO. This was accomplished by:

- Conducting a review of available literature;
- Conducting a phone and email survey of Texas oil and gas producers;
- Researching the availability of emission factors specific to hydraulic pump engines and mud degassing;
- Analyzing the requirements of NSPS Subpart OOOO; and
- Proposing control factors and revised operating/equipment parameters to reflect the requirements of the NSPS.

ERG first conducted a review of available literature, looking for data on emissions from mud degassing, hydraulic pump engines, and the impacts of NSPS Subpart OOOO, which affects new or modified sources as early as August 2011, dependent upon equipment type. Academic and technical literature on equipment characterization, emissions control techniques, and available state and federal environmental agency guidance on calculating emissions from these operations were examined. Additionally, ERG conducted a targeted phone survey of Texas oil and gas producers, requesting information on the use of hydraulic pump engines and mud degassing operations at their oil and gas wells. Several oil and gas producers were interviewed, to gather information on current practices and trends in the industry that are specific to Texas.

Using this information, ERG developed region-specific activity data and emission factors for use in updating the statewide oil and gas nonpoint area source emissions inventory for the source categories of interest.

2. Oil and Gas Producing Regions in Texas

There are several distinct oil- and gas-producing regions in Texas. These regions, also referred to as basins, reservoirs, source rock, or productive formations, are characterized by differences in petrogeology, age, depth below surface, type of petroleum hydrocarbon produced (liquids, gas, both), and many other characteristics that make them unique from one another. Even within a single region, there exists considerable heterogeneity. These differences are very important for evaluating the emissions that occur from production activities at wells in these basins. Drilling companies, fracturing companies, and production companies (operators) utilize practices that may be unique to each region, and emissions from their activities can vary accordingly. This study accounts for these differences, where they are known.

Figure 2-1 identifies eight oil and gas basins found in Texas. These basin boundaries are determined at the level of the county, and are based on geographical areas having similar petrogeology. By doing this, emissions from oil and gas production activities can be more accurately allocated to a county, based on county-level activity and production data, and emission factors determined at the basin-level. Note that the Eagle Ford Shale has historically been considered part of the Western Gulf Basin for inventory purposes, but due to the recent high level of activity in this area, it has been broken out as a separate region to more accurately characterize the unique types of processes and operations occurring to develop this play.

TCEQ's nonpoint area source air emissions inventory estimates for upstream oil and gas operations are based on county-level activity and equipment/emissions profiles. Activity data, such as oil and gas well counts and oil and gas production are as reported by the Railroad Commission of Texas (RRC)[1]. The equipment characterization and emissions data used in the inventory has been developed and refined over the last several years from a variety of studies, including TCEQ's "*Characterization of Oil and Gas Production Equipment and Develop a Methodology to Estimate Statewide Emissions*" [2] and a 2012 study "*2011 Oil and Gas Emission Inventory Enhancement Project for CenSARA States*" conducted by the Central States Air Resources Agencies (CenSARA).[3]

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[1] 2013 oil and gas activity data provided by the TCEQ, based on a January 2014 extract of information by the RRC and provided to the TCEQ in March 2014.

[2] "Characterization of Oil and Gas Production Equipment and Develop a Methodology to Estimate Statewide missions", TCEQ, November 24, 2010.

[3] "2011 Oil and Gas Emission Inventory Enhancement Project for CenSARA States", Environ International Corporation and Eastern Research Group, Inc. December 21, 2012.

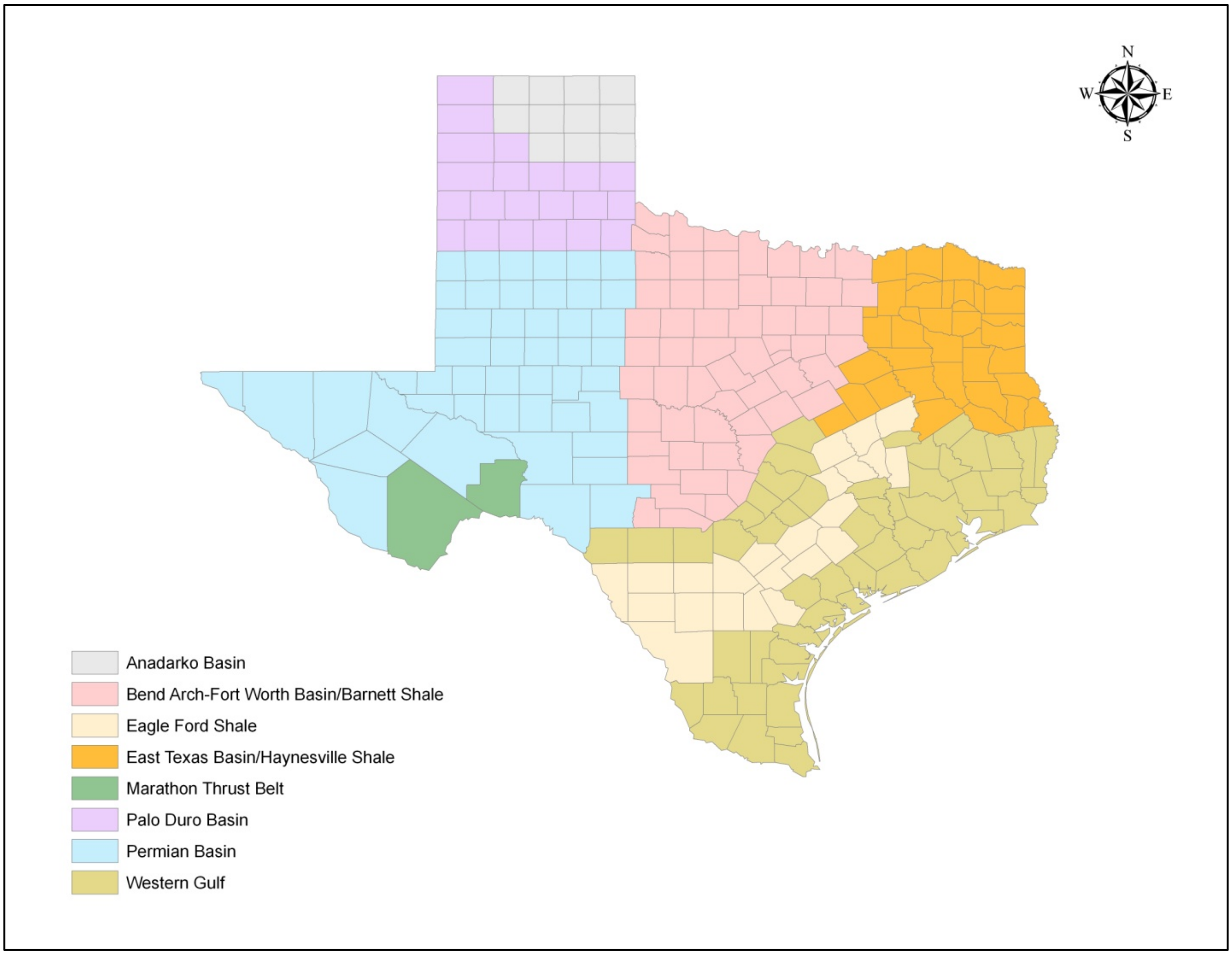

Figure 2-1. Oil and Gas Basins in Texas

This study sought to build upon these previous efforts to determine:

- Equipment characteristics and operational profiles of hydraulic pump engines used to stimulate wells in Texas;
- The appropriate emission factors to use for hydraulic pump engines used in Texas;
- The types of drilling mud used to drill oil and gas wells in Texas;
- The appropriate emissions profile data to use for mud degassing during oil and gas well drilling in Texas; and
- The implications of the recent revisions to the NSPS Subpart OOOO on the TCEQ nonpoint area source oil and gas emissions inventory.

3. Hydraulic Pump Engines

ERG investigated the use of hydraulic pump engines at drilling sites in Texas. The intent of this part of our study was to determine the frequency, quantity, location, and operating characteristics of these activities across the state, so that these emissions could be more accurately estimated in the TCEQ's nonpoint area source inventory. In arriving at the determinations presented in this report, ERG conducted a literature review, conducted a survey of oil and gas producers, gathered data on well completions from the RRC, reviewed data on engine emission factors, and interviewed industry representatives.

Hydraulic fracturing or stimulation involves the high pressure injection of a mixture of water, sand, proppants, and small amounts of chemicals and additives, to create fissures or fractures in rock formations. The fissures and fractures created during these operations stimulate an increase in the flow of natural gas and liquid hydrocarbons from the productive formation to the wellbore.[4] Hydraulic stimulation is used in petroleum-bearing formations that would normally be non-productive due to low porosity or permeability.[5] The intent is to increase the rate of recovery of petroleum liquids and gas from the reservoir surrounding the wellbore. Hydraulic stimulation is an expensive process, costing $135,000 or more per well[6], so operators use it when they judge that the increased productivity of the well will pay for the cost of this additional step.

3.1 Literature Review

ERG conducted a review of recent literature on well drilling techniques in general and hydraulic stimulation practices in particular, with the intent to gain a better understanding of the technique and the equipment required. ERG also reviewed literature on the petroleum geology in Texas, examining how well stimulation practices vary between the different oil and gas-producing formations in Texas. The following studies, articles, and web pages were found to be relevant.

3.1.1 Oil and Gas Emission Inventory, Eagle Ford Shale – Technical Report

The Alamo Area Council of Governments (AACOG), in cooperation with the TCEQ, published a study in April 2014, entitled "Oil and Gas Emission Inventory, Eagle Ford

4 Ginna Rodriguez and Chenchen Ouyang, "Air Emissions Characterization and Management For Natural Gas Hydraulic Fracturing Operations In the United States", Masters Thesis project, Univ. of Michigan, April 2013.

5 Porosity of a rock is a measure of the empty spaces) in a material, and is a fraction of the volume of void spaces divided by the total volume. Permeability is a measure of the ability of a material (such as rocks) to transmit fluids.

6 These are average cost figures for a USA well in 2011. Source: Michael Economides, "Hydraulic Fracturing: The State of the Art", Energy Tribune, August 26, 2011. Online: http://www.energytribune.com/8672/hydraulic-fracturing-the-state-of-the-art-2#sthash.rjPkQxRS.dpbs

Shale".[7] This study focused exclusively on the oil and gas operations in the Eagle Ford Shale formation in south Texas. The study examined the unique characteristics of the geology, hydrocarbon production, and production equipment used in the Eagle Ford Shale, and developed an air emissions inventory for oil and gas operations located in that region. The study gathered data on production, drill rig counts, well counts, well characteristics, and nonroad equipment from the RRC, companies that provide hydraulic pumping services,[8] TCEQ, oil and gas companies, and previous studies to compile a comprehensive view of the type and amount of equipment currently in use. The study then combined these activity data parameters with emissions factors from TCEQ's Drill Rigs Emission Inventory,[9] equipment manufacturers, the results of Texas Center for Applied Technology (TCAT) surveys,[10] and other sources, to develop an air emissions inventory. The study also examined development trends in the region, and, based on predicted production increases in the future, developed estimates of air emissions for 2015 and 2018 under three development scenarios.[11]

Of particular significance to this present study is the fact that the AACOG study estimated emissions from the use of hydraulic pump engines in the Eagle Ford Shale for the year 2012. The study examined data on hydraulic stimulation activity from studies done on other shale plays such as in Colorado,[12] the Marcellus Shale[13] in the northeast, the Barnett[14] and Haynesville[15] Shales in Texas, and from studies done by Ohio EPA and

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[7] This study was finalized by the authors on November 30th, 2013 and accepted as final by TCEQ on April 4, 2014.

[8] Schlumberger, Baker-Hughes, and Halliburton are three of the largest companies providing hydraulic pumping services for the oil and gas production industry.

[9] Texas Commission on Environmental Quality, "Development of Texas Statewide Drilling Rigs Emission Inventories for the Years 1990, 1993, 1996, and 1999 through 2040", by Eastern Research Group, Inc., August 15, 2011. Online: http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5821199776FY1105-20110815-ergi-drilling_rig_ei.pdf

[10] Texas Center for Applied Technology (TCAT), "Environmentally Friendly Drilling Systems Program Hydraulic Fracturing Phase Emissions Profile (Air Emissions Field Survey No. 1)", Nov. 2011.

[11] The study predicted air emissions under low, medium and high development scenarios. These development scenarios were based on estimates of ultimate recoverable reserves from the region, the number of drill rigs available, interviews with industry representatives about their plans for future development, production decline curves for wells in the region, and the prices for natural gas and petroleum liquids.

[12] Amnon Bar-Ilan, John Grant, Rajashi Parikh, Ralph Morris, ENVIRON International Corporation, "Oil and Gas Mobile Sources Pilot Study", July 2011. Online: http://www.wrapair2.org/documents/2011-07_P3%20Study%20Report%20(Final%20July-2011).pdf

[13] All Consulting, "NY DEC SGEIS Information Requests". Prepared for Independent Oil & Gas Association, Project no.: 1284, Sept. 16, 2010. Online: http://catskillcitizens.org/learnmore/20100916IOGAResponsetoDECChesapeake_IOGAResponsetoDEC.pdf

[14] Al Armendariz, "Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements", Prepared for Environmental Defense Fund, Jan. 26, 2009. Online: http://www.edf.org/sites/default/files/9235_Barnett_Shale_Report.pdf

[15] John Grant, Lynsey Parker, Amnon Bar-Ilan, Sue Kemball-Cook, and Greg Yarwood, ENVIRON International Corporation, "Development of an Emission Inventory for Natural Gas Exploration and Production in the Haynesville Shale and Evaluation of Ozone Impacts", August 31, 2009. Online: http://www.netac.org/UserFiles/File/NETAC/9_29_09/Enclosure_2b.pdf

the U.S. Dept. of Interior.[16] The AACOG study's authors also interviewed industry representatives, gathering information on how hydraulic stimulation equipment and processes have changed over time. The interviewers gathered information on: engine horsepower, the average amount of time it took to fracture a well, the number of fracturing stages, load factor, and the amount of water used. Like this study, the previous studies cited in the AACOG report used engine count, engine horsepower, hours of operation, and load factor to determine the emissions from a typical hydraulic fracturing job. Unlike this present study, the AACOG report used aerial imagery as part of their basis for estimating the number of hydraulic pump engines used at sites in the Eagle Ford Shale. Although imagery from 14 sites indicated that an average of 13.9 engines were used, the study's authors choose to use 12 engines per site in their emissions calculations, based on data from other studies and information obtained from local fracturing companies. The AACOG study based their load factor (30%) on information collected from hydraulic pump operators in the Eagle Ford play. The factors used in the AACOG study for calculating engine emissions from hydraulic fracturing are shown in Table 3-1.

Table 3-1. Emission Factors Used for Calculating Engine Emissions

Factor Description	Factor and Units	Source:
Number of Engines	12 / job	TCAT Eagle Ford Survey, ERG's Fort Worth Natural Gas Study, Aerial Imagery, Local Sources
Engine Horsepower	2,250 hp	TCAT Eagle Ford Survey, ERG's Drill Rig Emission Inventory for TCEQ
Total Hours per Job	54 hrs / job	ENVIRON's Haynesville Shale Report
Load Factor	30%	Local Sources
Engine Emission Factors	4.56g NO_x/hp-hr 0.24g VOC/hp-hr 2.67g CO/hp-hr	TCEQ's TERP emission factors for Tier 2 Engines[17] TCEQ's TERP emission factors for Tier 2 Engines TexN Model[18]

Thus, the AACOG study concluded that the total power expended by hydraulic pump engines to stimulate a typical well in the Eagle Ford Shale is 437,400 hp-hr.

The study noted that hydraulic stimulation practices have changed in the last few years, and described some of those changes. As more wells are completed in the Eagle Ford play, operators gain a better understanding of what works best in the geologic conditions presented by the source rock in the Eagle Ford Shale. A careful comparison

16 U.S. Department of the Interior, Bureau of Land Management, "Tumbleweed II Exploratory Natural Gas Drilling Project", DOI-BLM-UTG010-2009-0090-EA, June 2010. Online: http://www.blm.gov/pgdata/etc/medialib/blm/ut/lands_and_minerals/oil_and_gas/november_2011.Par.24530.File.dat/

17 TCEQ, April 24, 2010. "Texas Emissions Reduction Plan (TERP): Emissions Reduction Incentive Grants Program Technical Supplement No. 2, Non-Road Equipment".

18 TCEQ, August 18, 2008, Texas NONROAD (TexN) Model Version 1.0, Online: ftp://amdaftp.tceq.texas.gov/pub/Nonroad_EI/TexN/TexN_Users_Guide.pdf

of the AACOG study data and that from studies of hydraulic completions in other shale plays revealed that the techniques in the Eagle Ford that produce the best results are qualitatively different than those practices that lead to good results in other plays. This will be examined further in the next study reviewed for this report.

3.1.2 Hydraulic Technology – Optimizing Completion Design for the Eagle Ford Shale

ERG reviewed two studies published in The American Oil and Gas Reporter that detailed new approaches to hydraulic fracturing in the Eagle Ford Shale.

A study entitled "Approach Optimizes Completion Design", published in the August 2011 edition of The American Oil and Gas Reporter[19] examined the effect of a reservoir-specific completion strategy that accounts for the site-specific characteristics of the reservoir rock. The source rock at a well in DeWitt County was studied prior to fracturing. Analysis revealed that the reservoir rock was a clay-rich limestone with low quartz content and a low Young's modulus,[20] compared to the rock in the Barnett Shale, which is a very brittle siltstone with a high Young's modulus. The study examined how the properties of the reservoir rock played a role in determining what fracturing procedures and materials would provide the best results in opening the reservoir rock to allow the maximum gas and liquids to flow to the wellbore. Whole core data from a vertical section and mud log data from the lateral section were examined for the rocks' petrophysical characteristics and used to develop a completion strategy for each stage of the completion. The fluid mix was designed to control clay swelling, decrease the viscosity of the fluid over time, and inject larger than normal sized proppants to account for the relative softness of the rock. The large proppants were chosen to prevent 100% embedment of the proppant in the fracture face, which would, in effect, seal up the fractures that the hydraulic pumps create during the process. Each stage of the lateral was completed differently to account for changes in the brittleness/ductility index of the rock. Production data from the well, compared to that from other wells, showed that the production on this hybrid completion was superior to that produced from similar wells completed in the Eagle Ford using slick-water fracs.[21] The study authors concluded that the higher conductivity achieved with the hybrid completion accounted for the higher production.

[19] The American Oil and Gas Reporter, "Approach Optimizes Completion Design", R. Borstmayer, N. Sargent, A. Wagner, and J. Mullen, August 2011.

[20] Young's Modulus is a measure of the stiffness of an elastic isotropic material and is used to predict how much a material sample extends under tension or shortens under compression. It might also be considered a measure of the brittleness or ductility of the rock.

[21] Compared to production from the three slick-water fraced wells examined in the study, production from the hybrid fraced well ranged from 750 – 2,250% higher, based on barrel oil equivalent production of gas and oil.

This 2011 study, published in a widely-available industry publication, showed that using a site-specific hybrid completion technique unique to the Eagle Ford Shale can increase well production by significant margins over using a completion technique typically used in other shale plays. ERG assumes that all other fracturing companies working in the Eagle Ford will quickly adopt these techniques. Although the study did state that the lateral length was 3,800 feet, it did not publish any information on the engine power or time spent to fracture each of the 11 stages. Therefore, total engine power requirements for this well could not be compared to the results from other studies conducted on other shale plays.

A study entitled "Pilot Wells Test Stimulation Approach", published in the June 2011 edition of The American Oil and Gas Reporter[22] examined the effect of monitoring real-time microseismic activity in the reservoir rock during hydraulic fracturing for two wells. The study examined the effect of changing the hydraulic pumping schedule (pressure, time, proppants) using the microseismic monitoring, and found that "a stimulation technique that uses a shutdown during pumping to allow pressure relaxation, or equilibration, prior to reinitiating the fracturing process proved highly successful in increasing the estimated stimulated volume (ESV) in the reservoir rock." The stimulation team changed their techniques for each stage of fracturing, varying the pressure and timing, based on the microseismic results from previous stages, with the intent to contain the fracturing within the target zone (which ranges from 100 to 300+ feet thick). The production logs from the wells showed positive correlation "between production contribution and the ESV derived from the analysis of microseismic monitoring done during hydraulic stimulation." For the first well, pressure was slowly increased for each stage, containing the fracture in the target zone. For the second well, the stimulation team utilized significant variations in pumping pressure for five of the seventeen stages, to allow pressure relaxation for a period of 2 – 14 hours, prior to resuming pumping and finishing the fracture stage.

This article reported average lateral lengths were greater than 5,000 feet, and the number of stages at 10 -17 per lateral. The study did not publish any information on the engine power or time spent to hydraulically stimulate either of these wells. Therefore, total engine power requirements for these wells could not be compared to the results from other studies conducted on other shale plays.

[22] The American Oil and Gas Reporter, "Pilot Wells Test Stimulation Approach" A. Inamdar, T. Ogundare, D. Purcell, R. Malpani, K. Atwood, K. Brook, and A. Erwemi, June 2011.

3.1.3 Comparing Emissions from Hydraulic Operations Using Activity Data and Fuel Consumption

A Masters' Thesis project examined emissions from hydraulic stimulation operations in both the Eagle Ford Shale and the Marcellus Shale.[23] This study was unique in that the authors evaluated five air emissions models: three models were based on activity levels per source and two models were based on fuel consumption per source. The three models based on activity levels used data and methodology similar to that used in the AACOG study described above, the differences being in the use of load factors and emission factors. The general equation for these three activity-based models is:

Emissions = emission factor x horsepower x load factor x operating time.

The models based on fuel consumption differed in that one used total fuel consumption and AP-42 emission factors[24] while the second calculated emissions based on fuel consumption rate, hours of operation, and EPA Nonroad Tier 2 standards.[25] Both fuel consumption models used a constant for fuel density (7.11 lb/gal) and brake-specific fuel consumption for the equipment. The general equation for the two fuel usage models is:

Emissions = emission factor x brake-specific fuel consumption x fuel density x fuel consumption

The authors collected detailed engine activity and fuel usage data[26] from two well fracturing sites and applied it to the five models. The five models are described in Table 3-2.

Table 3-2. Emission Models Used for Estimating Emissions

Model	Source of Engine Emission Factors	Assumptions[27]
Activity Model 1	U.S.EPA – AP-42, Chapter 3.4	100% Load
Activity Model 2	U.S.EPA – AP-42, Chapter 3.4	Average Load, based on local data
Activity Model 3	U.S.EPA – Nonroad Tier 2 standards	Average Load, based on local data
Fuel Usage Model 1	U.S.EPA – AP-42, Chapter 3.4	100% Load
Fuel Usage Model 2	U.S.EPA – Nonroad Tier 2 standards	Average Load, based on local data

[23] Ginna Rodriguez and Chenchen Ouyang, "Air Emissions Characterization and Management For Natural Gas Hydraulic Fracturing Operations in the United States", Masters Thesis project, Univ. of Michigan, April 2013.
[24] Emission factors were from AP-42, Chapter 3.4, Large Stationary Diesel and All Stationary Dual-fuel Engines, October 1996**.**
[25] All of the frac pump engines in the study were Tier 2 models.
[26] The authors determined that the average fuel used for a fracturing job is 22,100 gallons for the Eagle Ford Shale and 20,800 gallons for the Marcellus Shale.
[27] The average load factor is based on data collected onsite, and then weighting different loads during different portions of the job over the total time the frac pumps are used. For Fuel Usage Model 2, the fuel consumption rate is based on average load.

Total emissions were calculated from the engines used to power the hydraulic pumps, blender, frac control unit, hydration unit, sand king, and water transfer pump for each of the five models. By comparing results from the five models, the authors found that the magnitude of emissions is most sensitive to the emission factor and the load factor for the engines. The study found that emissions from the hydraulic pump engines account for 83-94% of all emissions from the engines used in hydraulic fracturing operations.

3.1.4 Hydraulic Stimulation in the Haynesville Shale

The Halliburton Company, a major provider of hydraulic pump services, produced a short brochure on the complex, heterogeneous conditions in the Haynesville Shale.[28] The brochure included the following information:

- The Haynesville Shale is approximately 10,500–13,500 ft deep, and its porosity is higher than other shales, indicating its ability to contain more gas;
- It has higher reservoir pressure than other North American unconventional shale plays;
- Average well vertical depths are 11,800 ft with bottomhole temperatures averaging 330°F, and wellhead treating pressures during stimulation commonly exceeding 10,000 psi. As a result, wells here *require almost twice the amount of hydraulic horsepower*[29] and more advanced fluid chemistry than other shale plays in the Southern U.S.; and
- In these deep wells, with fracture gradients of 1 psi/ft and low Young's modulus, there is also concern about the ability to sustain production with adequate fracture conductivity.

Based on the low Young's modulus, ERG would expect that the proppants used in the Haynesville Shale would be similar to that used in Eagle Ford Shale (e.g., larger in size), in order to maintain fracture conductivity to the wellbore after the fracture process is completed.

3.2 Hydraulic Pump Engine Survey and Findings

The hydraulic pump engines survey targeted oil and gas production companies and attempted to obtain information on the use of hydraulic pump engines during well completion activities at oil and gas wells. The companies targeted had significant recent activity in the six regions of interest for the survey.

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[28] Halliburton, Haynesville Shale, http://www.halliburton.com/en-US/ps/solutions/unconventional-resources/shale-gas-oil/shale-plays/haynesville-shale.page?node-id=hgjyd46z and http://www.halliburton.com/en-US/ps/solutions/unconventional-resources/shale-gas-oil/shale-plays/haynesville-shale.page?node-id=hgjyd46z

[29] While ERG's survey results for wells in the Haynesville Shale of East Texas appear to be at odds with this claim, the one company that submitted survey data gave us data for 7 vertical wells. The Halliburton Company is referencing the amount of hydraulic horsepower needed for stimulation of horizontal wells.

For the hydraulic pump engine survey, ERG attempted to contact persons at oil and gas production companies who were responsible for environmental and regulatory compliance. Letters were sent to a total of 93 contacts at 86 separate regional company offices located in Texas, Oklahoma, and surrounding states. The letters explained the survey, requested cooperation in gathering data, and included sample data collection forms. The survey letter requested data on the location, the type of well, the number of engines used, the horsepower of the engines, the percent full load for the engines, the number of fracturing stages, and the duration of each fracturing stage. The companies selected were identified from previous TCEQ surveys as companies which had provided data, and from the RRC database as operating companies that completed a significant[30] number of wells in the targeted basins during the year 2013. See Attachment A for the hydraulic pump engine letter and survey materials.

ERG followed up the letters with phone calls to each company contact until contact was made. In many cases, emails were sent to the company, either as a follow up to a telephone conversation, or in the event no telephone contact could be made. During phone calls, ERG requested participation and explained the survey to potential respondents.

ERG collected data on the use of hydraulic pump engines used during well completions for 79 wells from nine companies. The survey asked questions about:

- Location (County);
- Type of well (oil or gas well);
- Number of engines used;
- Horsepower of the engines;
- Percent full load for the engines;
- Number of fracturing stages; and
- Duration of each fracturing stage.

The data submitted for these 79 wells was compared with RRC data on the actual number of horizontal and vertical wells completed by each reporting company in 2013, by region and county, well type (oil or gas) and wellbore profile (horizontal, vertical, directional). The data was compiled into a spreadsheet, sorted by region, and calculations were performed to determine basin and state averages. This data is shown in Table 3-3:

[30] For purposes of this survey, a ‘significant’ number of wells completed by an operating company in 2013 ranged from 12 to over 100. Companies were found by querying the RRC database on the number of well completions, by district.

Table 3-3. Hydraulic Pump Engine Survey Data, by Region

Basin	Average Number of Engines	Average Horsepower	Average % Load	Average Number of Fracturing Stages	Average Duration of each Stage (hours)	Average Total Horsepower-hours Per Job
Anadarko Basin	15	2200	48%	10.4	1.58	254,563
Eagle Ford Shale	23	2290	76%	16.6	2.28	1,223,667
East Texas Basin/Haynesville Shale	8	1814	36%	2.1	1.04	11,271
Permian Basin	10	2313	36%	16.8	1.38	266,639
Statewide Average	14	2154	49%	11.5	1.57	439,035

Seven (7) additional companies responded to the survey with information to the effect that "Our company has not fractured any wells in those counties in 2013." ERG considered this to be useful information, as it provided information on those newly completed wells that were not hydraulically stimulated.

ERG obtained information on all 16 company's wells from the RRC database[31] for the basins of interest. This data included the region and county, well type (oil or gas) and wellbore profile (horizontal, vertical, directional). The number of wells represented by companies that responded but did not fracture any wells typically only represented a few wells. Many of these companies produced natural gas, and the market prices for natural gas for the past few years have not supported any new exploration. This data is shown in Table 3-4.

Table 3-4. Companies Responding to the Survey

Region	Companies Who Filled Out Survey Completely	Companies Reporting "No Wells Fractured"	Number of Wells Reported	Number of Wells Completed in 2013	Wells Completed in 2013 by Reporter	Reporter's 2013 Wells as % of Total
Anadarko Basin	1	0	8	847	111	13.1%
Eagle Ford Shale	5	0	48	3,182	654	20.6%
East Texas Basin/Haynesville Shale	1	0	7	678	7	1.03%
Fort Worth	0	1	-	-	-	-
Permian Basin	2	2	16	8,864	382	4.3%
Western Gulf	0	4	-	-	-	-

[31] Data for well completions in 2013 was obtained using an operator-specific data query on the Railroad Commission website. Online: http://www.rrc.state.tx.us/about-us/resource-center/research/online-research-queries/

Attachment C contains the results of the hydraulic pump engine survey.

3.3 Recommendations for Using the Survey Findings

ERG recommends that the TCEQ use the findings in Table 3-3 above for estimating emissions from hydraulic pump engines. Where basin data was available, it has been used. For all other basins, the individual basin factors were averaged to determine a statewide value, which was then used in the other basins.

3.4 Hydraulic Pump Engine Emission Factors

For the 2011 base year TCEQ oil and gas nonpoint area source inventory, TCEQ used emission factors from the 2012 CenSARA study, which were derived using EPA's NONROAD2008 model. To update these factors for this study, average emission factors for 2013 and 2014 inventory years were developed. Using EPA's NONROAD2008 model, updated factors were developed based on the oil equipment source category bin (SCC 2270010010), and a diesel sulfur content of 15 ppm. Average emission factors were developed for engines between 1,000 and 3,000 horsepower, consistent with the engine sizes observed in the survey.

Table 3-5 below shows the emission factors for hydraulic pump engines for the 2011, 2013, and 2014 inventory years. As can be seen in the table, the emission factors have decreased over time as new engines replace older engines, resulting in a higher percentage of engines subject to the more stringent Tier 4 engine standards.

Table 3-5. Hydraulic Pump Engine Emission Factors

Pollutant	2011 (g/hp-hr)[a]	2013 (g/hp-hr)[b]	2014 (g/hp-hr)[b]
PM_{10}	0.227	0.184	0.172
NO_x	5.831	5.081	4.775
CO	1.318	1.076	1.021
VOC[c]	0.368	0.328	0.317
SO_2	0.010	0.0046	0.0045

[a] 2011 emission factors from CenSARA Inventory.
[b] 2013 and 2014 emission factors from EPA's NONROAD Model.
[c] VOC emission factor includes exhaust and crankcase emissions.

To account for this updated hydraulic pump engine information in the inventory, the Hydraulic Fracturing Pumps tab of the TCEQ oil and gas nonpoint area source emissions estimation calculator was revised as follows:

- The PM_{10}, NO_x, CO, VOC, and SO_2 emission factors were updated to the 2013 values shown in Table 3-5;
- Table A was added to include the hydraulic pump engine operating characteristics for each basin from Table 3-3; and

- In the County-level emissions table: columns H through L were revised to lookup the appropriate operating factors from Table A.

Attachment D contains the updated TCEQ oil and gas nonpoint area source emissions estimation calculator ("ERG AppendixE_2013 with updates to Basin information.xls") reflecting the changes to the inventory for hydraulic pump engines using the updated operating characteristics and emission factor data in Tables 3-3 and 3-5.

4. Mud Degassing

Drilling mud is a mixture of special clays and additives with water, oil, or synthetic matter. Considerable heat and friction are generated by the drill bit as it removes rock at the bottom of the well. During drilling, the drilling mud is continuously pumped through the drill string and out through the drill bit. The circulating drilling fluid cools and lubricates the drill bit, and moves cuttings upwards through the wellbore toward the surface. Mud must have the capacity to suspend the fragments of solid material removed by the drill bit. If the mud does not circulate quickly enough, the drilled cuttings in the wellbore may accumulate and the drill string may get stuck.

To properly control the drilled materials and cutting suspension, the properties of drilling fluid are tested frequently at the rig site by a mud engineer using procedures specified in "Recommended Practice for Field Testing Water-Based Drilling Fluids", API Standard Method RP 13B-1. Measured properties include density and viscosity. Viscosity must be high enough that the drill cuttings will remain suspended, but low enough such that the pumps can overcome the friction and pump the mud up and out of the wellbore. Low-viscosity mud allows sand and cuttings to settle out, and gas to escape at the surface.[32] Mud density must be carefully controlled, and is gradually increased by the mud engineer through addition of special additives to the drill mud as the depth of the well increases. This is done to counteract formation pressure, which increases with depth.

As the drill bit approaches and penetrates oil and gas-bearing layers of rock (the producing formation or "play"), the mud engineer must be sure that the weight of the column of mud exceeds the pressure of fluids or gases in the productive formation. If not, and the subsurface pressure exceeds the downward pressure from the weight of the mud in the wellbore, a blowout may occur. Blowouts are both costly and dangerous, and drilling companies take extensive measures to prevent them. Still, the RRC records indicate that 24 blowouts occurred in Texas in 2013.[33]

In a broad sense, drilling mud can be classified as water-based, oil-based, synthetic, or an emulsion. The term "oil-based" is used for drilling mud prepared from petroleum distilled liquids, whereas the term "synthetic" is used for drilling mud prepared from non-aqueous liquids prepared from the reaction of organic building blocks, such as ethylene or methane.[34] Water-based muds may be fresh or saltwater based and typically include a type of clay that will stay suspended for a time after agitation has stopped. Oil-

[32] Lyons, William C. Working Guide to Drilling Equipment and Operations. Amsterdam: Gulf Pub./Elsevier, 2010. <http://public.eblib.com/EBLPublic/PublicView.do?ptiID=535200>.

[33] Railroad Commission of Texas, "Blowouts and Well Control Problems", Online: http://www.rrc.state.tx.us/oil-gas/compliance-enforcement/blowouts-and-well-control-problems/

[34] Growcock, Frederick B., and Arvind D. Patel. "The Revolution in Non-Aqueous Drilling Fluids (AADE-11-NTCE-33)." AADE National Technical Conference and Exhibition Held at the Hilton Houston North Hotel, Houston, Texas, April 12-14, 2011. (2011). <http://www.slb.com/resources/technical_papers/miswaco/AADE-11-NTCE-33.aspx>.

based and synthetic muds are generally expensive and hard to dispose of, but they are well suited for drilling the producing zones of deep, high temperature holes in which water-based muds solidify. [35]

Under-balanced drilling (UBD) describes a situation in which the hydrodynamic pressure of the drilling mud and circulating fluids in the well bore is less than the pressure of the well formation. This drilling technique can require surface equipment to separate drilling mud and hydrocarbons for recirculation, storage, flaring, and disposal.[36] UBD can cause a kick or a blowout to occur where there is an influx of reservoir fluid or gas into the wellbore. When properly managed, UBD allows for greater drilling velocity (aka rate of penetration). [37] When mud is over-balanced, it is forced into the surrounding rocks, and the solid particles form a filter or mud cake. This stabilizes the sides of the well and prevents subsurface fluids from flowing into the well. Over-balanced drilling is more typical.[38]

It is common to have a mud gas separator or degasser equipment located at the surface of the well to separate and safely remove large pockets of free gas from the drilling mud returned to the surface, but one is only used when drilling through the producing formation. It is necessary to remove the gas because it reduces the mud weight. Gas separators are effective on both water-based and oil-based muds. The vented gas may include toxic gases (such as hydrogen sulfide) from the drilling fluids processing system. One manufacturer of mud gas separators, GN Solids America, equips their separators with an electric ignition device to flare toxic gases.[39] Vacuum separators utilize negative pressure to withdraw entrained gases from the mud. In order for this to work, mud exiting the wellbore is pumped through a venturi choke. The pressure drops on the outlet side of the choke, enabling the entrained gases to expand and easily separate from the drilling mud. Atmospheric separators pump mud into a thin layer, relying on density differences between the gas and the mud to liberate gas. One separator design utilizes the thin layer approach inside a vacuum chamber to speed separation of gas from the drilling mud.

4.1 Available Mud Degassing Emission Factors

Limited information on the emissions from drilling mud is available, but there is a consensus opinion that a 1977 U.S. EPA publication "*Atmospheric Emissions from*

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[35] Lyons, William C. Working Guide to Drilling Equipment and Operations. Amsterdam: Gulf Pub./Elsevier, 2010. <http://public.eblib.com/EBLPublic/PublicView.do?ptiID=535200>.

[36] LeBlanc, Chris, Marco Amorim, and Roberto Piacentini. "Case Study: a High Throughput Mud-Gas Separator for Underbalanced Drilling." Offshore Technology Conference Held in Rio De Jeneiro, Brazil, 4-6 October 2011

[37] Personal communication with Bill Brannan of Nicklos Drilling Company. June 6, 2014

[38] Oil & Gas Production Protocol, published in February 2010 by The Climate Registry

[39] GN Solids America LLC. "Mud Gas Separator - GNZYQ Mud Gas Separator Features and Benefits." Web Accessed: 11 June 2014. <http://www.gnsolidsamerica.com/mud-gas-separator.html>.

Offshore Oil and Gas Development and Production" [40] is the best currently available estimate. The estimate presented in this study is based on engineering calculations of emissions from mud degassing at an offshore gas well using a water-based mud. The water-based emission rate represents gas liberated from rock drilled out of the wellbore, when drilling through a producing formation. The calculation assumes a penetration rate of 400 feet per day, 25% porosity, and reservoir pressure of 4,000 psig. The oil-based emission rate was calculated by assuming emissions from oil-based drilling mud were equivalent to emissions from diesel fuel stored in a fixed-roof storage tank with a turnover factor of 0.5.[41] The surface area of exposed mud is small. The gases separated from the mud in the mud separator are not counted. Although the mud turnover speeds vary over the course of the drilling event, this was not considered.

Four recent publications cite the 1977 EPA report as the original source for mud degassing factors:

- The American Petroleum Institute (API) publication "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry"[42] discusses mud degassing, and recommends that "site-specific methane concentration data should be used to estimate these emissions". The API document cites the mud degassing emission factors reported by US EPA in 1977.
- The Climate Registry's "Oil and Gas Production Protocol"[43] discusses emissions from mud degassing in the case of an underbalanced drilling operation, where the pressure in the wellbore is kept lower than the gas and fluid pressure in the formation being drilled. However, the discussion lacks a specific formula, and states that the volume of gas vented must be measured or estimated based on downhole pressure, wellbore diameter, and the duration of underbalanced drilling. Although other publications have mentioned that the drilling penetration rate is faster, and formation damage is lessened using underbalanced drilling, none suggests that underbalanced drilling is used when drilling producing shale formations, due to the risk of blowout. The Climate Registry document cites the mud degassing emission factors reported by US EPA in 1977.
- A report prepared by ENVIRON and ERG for the CenSARA States[44] cites the mud degassing emission factors reported by US EPA in 1977; and
- A report prepared by ERG for the TCEQ[45] cites the mud degassing emission factors reported by US EPA in 1977.

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40 "Atmospheric Emissions from Offshore Oil and Gas Development and Production". U.S. Environmental Protection Agency, EPA-450/3-77-026, June, 1977.

41 Turnover factor is the ratio of throughput to tank capacity [See US EPA – Office of Air Quality Planning and Standards. Compilation of Air Pollutant Emission Factors AP-42, Section 7.1 Organic Liquid Storage Tanks. September 2006].

42 American Petroleum Institute, "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry", August 2009

43 Climate Registry, "Oil and Gas Production Protocol", Version 1.0, February 2010.

44 ENVIRON, "2011 Oil and Gas Emission Inventory Enhancement Project for CenSARA States", prepared for the Central States Air Resources Agencies, December 21, 2012.

45 Eastern Research Group, "Offshore Oil and Gas Platform Report - Final Report", August 16, 2010.

The most generally recognized mud degassing emissions factors are shown in Table 4-1, as presented in the API Compendium document.

Table 4-1. Mud Degassing Vented Emission Factors

Mud Type	Emission Factor (tonnes CH_4 / drilling day)[a]
Water-based	0.2605
Oil-based	0.0586
Synthetic	0.0586

[a] Note: 1 tonne = 1 metric ton = 2, 204.62262 pounds.

Additionally, the following studies were reviewed:

- In a recent study[46] published in the Proceedings of the National Academy of Sciences, the results of aerial sampling of methane in the air above wells being drilled in southwestern Pennsylvania (Marcellus Shale) was examined. The authors estimated that 34 grams methane per second was being released from wells in the drilling stage. Examination of the gas composition suggested that the methane plumes did not come from the shale rock, but arose from shallow coal pockets producing coal bed methane as the well was drilled through these formations. The methane was not directly attributed to drilling mud.
- A study sponsored by the Arkansas Department of Environment Quality entitled "Emissions Inventory & Ambient Air Monitoring of Natural Gas Production in the Fayetteville Shale Region"[47] examined air emissions from gas production activities in the Fayetteville Shale of Arkansas. Ambient monitoring was performed around the perimeter of six drilling sites, three hydraulic fracturing sites, four compressor stations, and a control site. The study found that concentrations of VOC at the sites other than drilling sites were at or below instrument detection limits, but that air samples around drilling sites had average VOC concentrations around 678 parts per billion.[48] The authors identified the likely source of VOC emissions as open tanks of oil-based drilling mud and cuttings.[49] The study did not identify the chemical composition of the VOC emissions, nor did it attempt to quantify emissions. The study noted that VOC emissions from gas production in the Fayetteville Shale were relatively low due to the low VOC content of the gas produced there (0.05% VOC), relative to the VOC content of gas produced in the Barnett Shale in Texas (8.2% VOC). Also, the Fayetteville Shale is a dry gas with little or no condensable hydrocarbons.

[46] Dana Caulton, et.al., "Toward A Better Understanding And Quantification Of Methane Emissions From Shale Gas Development", April 14, 2014. Online: http://www.pnas.org/content/early/2014/04/10/1316546111.abstract

[47] David Lyon & Toby Chu, Arkansas Dept. of Environmental Quality, "Emissions Inventory & Ambient Air Monitoring of Natural Gas Production in the Fayetteville Shale Region", November 22, 2011.

[48] Although there is no NAAQS standard for VOC, volatile hydrocarbons do contribute to ozone formation, and some of the VOCs produced during oil and gas exploration are also hazardous air pollutants. Without gas speciation data, the actual risk posed by these VOCs to the workers is unknown.

[49] A company drilling in the Fayetteville Shale reported that an average well required 8.4 days to drill with an average lateral length of 4,985 feet, and that drilling normally utilizes oil-based drilling mud.

These two studies show that knowledge of site- or region-specific VOC content of gases is necessary for accurately estimating emissions from mud degassing.

In addition to the literature review, a number of individuals were contacted in an effort to determine if there were any current or recent emissions studies directly evaluating emissions from drilling mud:

- ERG contacted Dr. David Allen at The University of Texas at Austin. Dr. Allen is part of a group researching the climate impacts of natural gas.[50] The group's paper "Measurements of methane emissions at natural gas production sites in the United States," made no reference to mud degassing measurements.[51] Dr. Allen was not aware of any ongoing efforts to further characterize emissions from mud degassing.
- ERG contacted API and URS (their contractor and lead author of the compendium). Neither was aware of any more recent studies on mud degassing. Karin C. Ritter of API was not aware of any such studies either, but agreed to relay the TCEQ's interest in evaluating emissions from mud degassing to API members. [52]
- ERG also contacted David Lyon, the author of the Fayetteville Shale study mentioned above, who is currently with the Environmental Defense Fund (EDF). EDF is currently conducting a series of studies looking at emissions from upstream and midstream oil and gas exploration and production activities. Mr. Lyon was not aware of past or present research into mud degassing beyond the studies identified above.[53]

4.2 Mud Degassing Vendor Data

ERG identified five manufacturers of mud degassers and attempted to contact them to obtain information on mud degasser usage patterns across Texas. Unfortunately, these companies were unwilling to share customer details or mud degasser usage patterns.

ERG also reviewed available online literature from companies that manufacture mud degassing equipment:

- Derrick Equipment Company,[54] based in Houston, Texas, manufactures a mud degassing machine that utilizes thin film, high surface area, impact, turbulence, and vacuum technologies to quickly and efficiently remove entrained gases from water and oil-based drilling muds. Combined with other equipment in their line of products, the degasser processes used drill mud so that it can be quickly reused in the drilling operation.

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50 Whittenberg, Lauren. "First Academic Study Released in EDF's Groundbreaking Methane Emissions Series." Environmental Defense Fund, 13 Sept. 2013. Accessed: 11 June 2014. <http://www.edf.org/media/first-academic-study-released-edf%E2%80%99s-groundbreaking-methane-emissions-series>.

51 Personal communication with Dr. David Allen at The University of Texas at Austin. April 30, 2014.

52 Personal communication with Karin C. Ritter of API and Terri Shires of URS Corporation. April 24, 2014 and April 29, 2014.

53 Personal communication with David Lyon, May 5, 2014.

54 Derrick Equipment Company, "Vacu-Flo Degasser", http://www.derrickequipment.com/home.aspx

- National Oilwell Varco,[55] based in Houston, Texas, manufactures a complete line of drilling fluid mixing, cleaning, cooling, pumping, and monitoring equipment. Their website indicates that "The mud (drilling fluid) system components condition the drilling fluid with the goal of lowering maintenance cost and decreasing the chance of equipment failure and hole and drilling problems."

While this vendor information provided background knowledge about the process and equipment used in mud degassing, no emissions information was available from these sources.

4.3 Mud Degassing Survey Findings

The mud degassing survey targeted drilling companies and attempted to obtain information relating to mud degassing activities during drilling operations at oil and gas wells. The drilling companies provide rigs, equipment and crews to drill and service wells. The companies targeted had significant recent activity in the six regions of interest for the survey. These regions of interest are: Anadarko basin, Permian basin, Western Gulf basin, Bend Arch-Fort Worth basin/Barnett Shale, East Texas basin/Haynesville Shale, and the Eagle Ford Shale. As there is little gas or oil production in the Palo Duro and Marathon Thrust Belt basins, these areas were not targeted in this survey.

For the mud degassing survey, ERG attempted to contact persons responsible for drilling operations at the regional offices of their respective companies. Letters were sent to a total of 111 contacts at 64 separate regional company offices, representing 38 different drilling companies. The letters explained the survey, requested cooperation in gathering data, and included sample data collection forms. The survey letter requested data on the location, the type of well, the type of drilling mud used, the number of drilling days per well, and any control equipment used. See Attachment B for the mud degassing letter and survey materials. The companies selected were identified from the RigData database as companies that had drilled a significant number of wells[56] in the six regions of interest in the past three years.

ERG followed up the letters with phone calls to each company contact until contact was made. In many cases, emails were sent to the company, either as a follow up to a telephone conversation, or in the event no telephone contact could be made. During phone calls, ERG requested participation and explained the survey to potential respondents.

The mud degassing survey failed to produce any useful results or data. Most of the drilling companies contacted did not respond to repeated voice messages left for them. Of the three contacts that ERG spoke with, all indicated that they did not have the

[55] National Oilwell VARCO, http://www.nov.com/home.aspx?langtype=1033

[56] For purposes of this survey, a 'significant' number of wells drilled by a drilling company ranged from 7 to 1198, depending upon the basin, with the average being 138.

information we were seeking, or that it would be too difficult to obtain. One respondent indicated that mud formulation is the purview of the oil and gas companies, and not the drilling contractor and that they did not maintain records of mud usage or composition.[57]

The lack of response to the mud degassing survey by the drilling operations personnel may be due to several reasons:

- Some companies may feel this type of information is confidential in nature and wish to protect their operating practices;
- Drilling companies are not used to responding to air quality data collection surveys, and do not have the institutional capacity to respond;
- There was no real incentive for the drilling companies to participate, as drilling companies do not report emissions from their operations directly to TCEQ, and have no formal relationship with TCEQ as a regulated entity;
- The information requested was either not kept by the drilling companies, or was saved in different departments within a company, making it inconvenient to compile information on a particular well; and
- The operations people contacted were too busy managing drilling operations to respond.

One respondent indicated that they could not count on the roughnecks to provide the correct information on the type of mud used at every stage in the drilling process. Another indicated that the mud engineer for the operations company (the owner of the well) would be the person that would have the information, and requested that we contact them directly. This approach proved unsuccessful as well.

4.4 Mud Degassing Emission Factors

While no useful data was obtained as part of the survey, ERG was able to develop basin-specific mud degassing emission factors for Texas based upon the API emission factors originally derived from the 1977 EPA study. Using natural gas dehydrator data derived from a recent TCEQ study,[58] natural gas composition profiles for five oil and gas basins in Texas were calculated, along with a state averaged natural gas composition profile. This information is shown in Table 4-2 below.

Use of the wet stream data for estimating mud degassing emissions from gas wells is appropriate, and such data is readily available through dehydrator emissions inventory reports submitted to TCEQ. The wet stream, or “wet gas” composition data from the dehydrators is assumed to be representative of the composition of any gas released during mud degassing. This information was then used to develop updated mud degassing emission factors for mud degassing at gas wells based on the Texas-specific gas composition data. The resultant mud degassing composition data as used in the emissions calculation is shown in Table 4-3.

[57] Personal communication with Bill Brannan of Nicklos Drilling Company. June 6, 2014

[58] “Condensate Tank Oil and Gas Activities”, Texas Commission on Environmental Quality, Air Quality Division, October 20, 2012.

Table 4-2. Basin-Level and State-Level Average Natural Gas Stream Composition Profiles

Composition in Weight %	Anadarko Basin		Bend Arch-Fort Worth Basin		East Texas Basin		Permian Basin		Western Gulf		State Average Profile	
	Dry Stream	Wet Stream	Dry Stream	Wet Stream	Dry Stream	Wet Stream	Dry Stream	Wet Stream	Dry Stream	Wet Stream	Dry Stream	Wet Stream
Water	0.04	0.13	0.01	0.11	0.01	0.12	0.01	0.13	0.01	0.11	0.01	0.11
Carbon Dioxide	1.54	1.57	4.02	4.00	4.18	4.14	2.00	1.84	2.66	2.66	3.32	3.32
Hydrogen Sulfide	0.06	0.06	0.00	0.00	0.00	0.00	0.18	0.17	0.00	0.45	0.05	0.16
Nitrogen	2.07	2.06	2.56	2.53	1.36	1.34	2.87	2.83	0.76	0.73	1.78	1.75
Methane	79.66	79.70	73.99	73.34	81.31	80.70	61.68	58.39	77.15	76.53	75.13	74.31
Ethane	6.57	6.56	8.25	8.18	5.93	6.02	12.97	12.64	7.24	7.19	7.99	7.88
Propane	4.20	4.20	4.95	5.02	2.53	2.57	9.44	11.02	4.80	4.79	4.96	5.11
Isobutane	0.83	0.83	0.95	0.97	0.90	0.93	1.42	1.64	1.49	1.48	1.17	1.22
n-Butane	1.72	1.72	1.89	2.06	1.00	1.02	3.31	4.39	1.58	1.57	1.78	1.95
Isopentane	0.63	0.63	0.76	0.83	0.60	0.67	1.21	1.34	0.92	0.92	0.84	0.87
n-Pentane	0.67	0.67	1.02	1.09	0.44	0.48	1.10	1.47	0.66	0.65	0.76	0.83
Cyclopentane	0.04	0.04	0.11	0.15	0.16	0.15	0.03	0.07	0.11	0.07	0.07	0.11
n-Hexane	0.47	0.28	0.23	0.54	0.24	0.24	0.66	0.72	0.23	0.27	0.27	0.41
Cyclohexane	0.05	0.05	0.18	0.13	0.14	0.14	0.36	0.43	0.22	0.27	0.18	0.22
Other Hexanes	0.66	0.66	0.32	0.27	0.48	0.52	0.99	1.16	0.78	0.69	0.59	0.59
Heptanes	0.33	0.33	0.42	0.42	0.33	0.39	0.67	0.65	0.37	0.48	0.42	0.42
Methylcyclohexane	0.11	0.11	0.10	0.10	0.05	0.11	0.19	0.18	0.21	0.21	0.16	0.21
Benzene	0.04	0.04	0.04	0.04	0.09	0.13	0.26	0.29	0.04	0.08	0.08	0.08
Toluene	0.05	0.05	0.01	0.01	0.05	0.05	0.18	0.17	0.05	0.10	0.05	0.05
Ethylbenzene	0.01	0.01	0.00	0.01	0.01	0.01	0.05	0.05	0.01	0.01	0.01	0.01
Xylenes	0.02	0.06	0.01	0.02	0.01	0.03	0.05	0.05	0.02	0.06	0.02	0.03
C8+ Heavies	0.25	0.25	0.18	0.18	0.19	0.25	0.38	0.37	0.67	0.67	0.36	0.36
VOC[a]	10.06	9.93	11.17	11.84	7.20	7.68	20.30	24.00	12.17	12.32	11.72	12.46
Total Hydrocarbons[b]	96.29	96.19	93.41	93.36	94.44	94.40	94.95	95.03	96.57	96.04	94.84	94.65

[a] VOC includes Propane through C8+ Heavies

[b] Total Hydrocarbons includes VOC, Methane, and Ethane

Table 4-3. Mud Degassing Composition (Gas Wells)

Basin	CH_4 mol %	VOC MW	VOC mol %
Anadarko	90.68	55.91	3.24
Bend Arch-Fort Worth	87.59	55.48	4.09
East Texas	91.49	59.04	2.37
Marathon Thrust Belt[a]	88.36	56.35	4.22
Palo Duro[a]	88.36	56.35	4.22
Permian	78.53	54.72	9.46
Western Gulf	89.94	57.60	4.03

[a] The data for Marathon Thrust Belt and Palo Duro is the statewide average.

For oil wells, use of the same natural gas dehydrator data is not appropriate since casinghead gas (gas produced from oil wells) typically has less methane (and more VOC) than gas produced at gas wells. Additionally, as the gas from oil wells is not always collected, the gas analysis data used to estimate emissions from dehydration and needed to develop the profiles shown in Table 4-2 will not be available.

Therefore, to develop Texas-specific mud degassing information for oil wells, ERG utilized data from the 2012 CenSARA study. As part of that effort, oil well mud degassing composition information was obtained for the Anadarko and Permian basins (with data for the Permian basin used for the Marathon Thrust Belt basin, which includes two counties in southwest Texas adjacent to the Permian basin). ERG then used the data from the Anadarko and Permian basins to develop a statewide averaged profile, which was applied to the remaining basins. Table 4-4 presents the results of this analysis.

Table 4-4. Mud Degassing Composition (Oil Wells)

Basin	CH_4 mol %	VOC MW	VOC mol %
Anadarko	82.93	55.42	5.98
Bend Arch-Fort Worth[a]	81.78	54.32	6.52
East Texas[a]	81.78	54.32	6.52
Marathon Thrust Belt	80.62	53.22	7.06
Palo Duro[a]	81.78	54.32	6.52
Permian	80.62	53.22	7.06
Western Gulf[a]	81.78	54.32	6.52

[a] The data for Bend Arch-Fort Worth, East Texas, Palo Duro, and Western Gulf is the statewide average.

Attachment D contains the updated TCEQ oil and gas nonpoint area source emissions estimation calculator ("ERG AppendixE_2013 with updates to Basin information.xls") reflecting the changes to the inventory for drilling mud degassing using the updated composition data in Tables 4-3 and 4-4.

5. NSPS Subpart OOOO Inventory Evaluation

The intent of NSPS Subpart OOOO[59] is to reduce emissions of criteria pollutants at new, modified, or reconstructed affected facilities at oil and gas production, gathering, gas processing, and gas transmission/storage sites. NSPS Subpart OOOO does not regulate greenhouse gas emissions or hazardous air pollutants.

The facility types affected by Subpart OOOO include: natural gas wells that are hydraulically fractured, centrifugal compressors using wet seals, reciprocating compressors, continuous bleed natural-gas driven pneumatic controllers, storage vessels with a potential to emit (PTE) six tons per year (tpy) or more of VOC, piping component equipment (pump, pressure relief device, open-ended valve or line, valve, and flange or other connector in VOC or wet gas service) within a process unit located at onshore natural gas processing plants, and sweetening units located at onshore natural gas processing plants. NSPS Subpart OOOO applies to these facilities if they are newly constructed, modified, or reconstructed after August 23, 2011. Compliance dates vary by the facility type.

Table 5-1 shows the affected facilities, industry segment, compliance standard, and compliance dates for oil and gas units and processes regulated under Subpart OOOO. Table 5-1 also indicates if the affected facility is included in TCEQ's oil and gas nonpoint area source inventory.

Table 5-1. NSPS Subpart OOOO Summary

Affected Facility	Area Source?	Industry Segment or Location	Compliance Standard	Compliance Date
Natural gas wells hydraulically-fractured prior to 1/1/2015	Yes	Well sites (production)	Combust flowback emissions from completions	10/15/2012
Natural gas wells hydraulically-fractured on or after 1/1/2015	Yes	Well sites (production)	Recover and reuse/sell or combust flowback emissions from completions	01/01/2015
Centrifugal compressors using wet seals	No	Gathering and NG processing plants	95% reduction of VOC	10/15/2012
Reciprocating compressors	No	Gathering and NG processing plants	Change rod packing every three years	10/15/2012
Continuous bleed natural-gas driven pneumatic controllers	Yes	Production (well sites) and gathering	6 scfh bleed rate	10/15/2012
Continuous bleed natural-gas driven pneumatic controllers	No	NG processing plants	Zero bleed rate	10/15/2012

59 40 CFR 60, Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, http://www.ecfr.gov/cgi-bin/text-idx?SID=f701fdccf601c0b3200249b0ca81fbb6&node=40:7.0.1.1.1.103&rgn=div6#40:7.0.1.1.1.103.297.2

Table 5-1. NSPS Subpart OOOO Summary

Affected Facility	Area Source?	Industry Segment or Location	Compliance Standard	Compliance Date
Group I Storage Vessels (construction, modification or reconstruction commenced after 8/23/2011 and on or before 4/12/2013)	Yes	Production (well sites), gathering, NG processing, and NG transmission sites	Reduce VOC emissions by 95%, or maintain actual VOC emissions at less than 4 tpy without controls	04/15/2015, or within 60 days after startup
Group II Storage Vessels (construction, modification or reconstruction commenced after April 12, 2013)	Yes	Production (well sites), gathering, NG processing, and NG transmission sites	Reduce VOC emissions by 95%, or maintain actual VOC emissions at less than 4 tpy without controls	04/15/2014, or within 60 days after startup
Equipment Leaks (pump, pressure relief device, open-ended valve or line, valve, and flange or other connector in VOC or wet gas service)	No	Onshore NG processing plants	Implement a LDAR program. Leaks > 500 ppm must be repaired.	10/15/2012
Sweetening Units	No	Onshore NG processing plants	Reduce SO_2 as calculated	10/15/2012

5.1 Construction, Modification, Reconstruction, and Affected Facilities

NSPS Subpart OOOO requirements apply only to the types of facilities listed above that are newly constructed, modified, or reconstructed after August 23, 2011. “Construction” is defined as the fabrication, erection, or installation of a new affected “facility.” Relocating an affected facility is not construction, modification, or reconstruction. “Modification” is defined as any physical or operational change to an existing facility which results in an increase in the hourly potential emission rate of any pollutant to which the NSPS standard applies.[60] Changes that do not constitute a modification include: increasing hours of operation, an increase in production rate without a capital expenditure, use of an alternative fuel or material if the source could utilize it prior, addition of an air pollution control device, change in ownership, and routine maintenance, repair, and replacement. “Reconstruction” is defined as replacing components at an existing facility, such that the capital cost of new components exceeds 50% of the capital cost of a comparable new facility, and it is technologically and economically feasible to meet applicable standards.

5.2 Effect of NSPS Subpart OOOO on the TCEQ Oil and Gas Nonpoint Area Source Oil and Gas Emissions Inventory

As shown above in Table 5-1, the following facilities/processes included in the TCEQ nonpoint area source inventory are affected by the rule:

[60] 40 CFR 60.14. An increase in emissions of a pollutant not regulated by the NSPS Subpart OOOO is not a modification.

- Natural gas wells hydraulically-fractured after 10/15/2012 and prior to 1/1/2015;
- Natural gas wells hydraulically-fractured on or after 1/1/2015;
- Continuous bleed natural-gas driven pneumatic controllers (at well sites);
- Group I Storage Vessels (at well sites); and
- Group II Storage Vessels (at well sites).

Since the NSPS regulations only affect facilities if they are newly constructed, modified, or reconstructed after August 23, 2011, an analysis was conducted to determine how to implement the required controls for each affected facility type in the inventory based on the requirements of the rule. Each of the affected source types is discussed in detail below, indicating how the affected percentage of the equipment population was determined, what the required controls are for each source type, and how these requirements were incorporated into the 2013 TCEQ oil and gas nonpoint area source emissions estimation calculator.

5.3 Natural Gas Well Completions

Under the requirements of NSPS Subpart OOOO, completions at natural gas wells that were hydraulically fractured after October 15, 2012 must be controlled with a flare. Completions at gas wells that are hydraulically fractured after January 1, 2015 must be controlled by capturing the gas for reuse or sale (reduced emissions completions) or flaring for exempted wells. There are currently no requirements in the rule to control emissions from oil well completions.

Information on the number of gas well completions that are hydraulically fractured is not readily available. However, information on the counts of vertical and horizontal gas wells spuds in 2013[61] is available. Therefore, ERG determined the percentage of gas well completions that were hydraulically fractured by assuming that the percentage of horizontal spuds in a county was equivalent to the percentage of horizontal completions, and that all horizontal well completions were hydraulically fractured. Using county-level data on the number of horizontal and vertical gas well spuds, the percent of all new gas wells that were horizontal, and therefore assumed to be hydraulically fractured, at the county level was determined. This data is included Table 5-2.

Table 5-2. Gas Well Completions

County	Vertical Spud Count	Horizontal Spud Count	% Horizontal Spuds
ANDERSON	0	0	0%
ANDREWS	1	0	0%
ANGELINA	0	2	100%
ARANSAS	2	0	0%
ARCHER	0	0	0%

[61] 2013 annual data was extracted January 2014 by the RRC and provided to TCEQ in March 2014.

Table 5-2. Gas Well Completions

County	Vertical Spud Count	Horizontal Spud Count	% Horizontal Spuds
ARMSTRONG	0	0	0%
ATASCOSA	0	0	0%
AUSTIN	0	1	100%
BAILEY	0	0	0%
BANDERA	0	0	0%
BASTROP	0	0	0%
BAYLOR	0	0	0%
BEE	25	5	17%
BELL	0	0	0%
BEXAR	0	0	0%
BLANCO	0	0	0%
BORDEN	0	0	0%
BOSQUE	0	0	0%
BOWIE	0	0	0%
BRAZORIA	4	8	67%
BRAZOS	0	0	0%
BREWSTER	0	0	0%
BRISCOE	0	0	0%
BROOKS	11	3	21%
BROWN	0	0	0%
BURLESON	0	0	0%
BURNET	0	0	0%
CALDWELL	0	0	0%
CALHOUN	1	0	0%
CALLAHAN	2	0	0%
CAMERON	0	0	0%
CAMP	0	0	0%
CARSON	0	0	0%
CASS	0	0	0%
CASTRO	0	0	0%
CHAMBERS	0	2	100%
CHEROKEE	4	1	20%
CHILDRESS	0	0	0%
CLAY	1	1	50%
COCHRAN	0	0	0%
COKE	0	0	0%
COLEMAN	1	0	0%
COLLIN	0	0	0%
COLLINGSWORTH	0	0	0%
COLORADO	0	2	100%
COMAL	0	0	0%
COMANCHE	1	0	0%
CONCHO	0	0	0%
COOKE	0	9	100%
CORYELL	0	0	0%
COTTLE	1	0	0%
CRANE	0	0	0%

Table 5-2. Gas Well Completions

County	Vertical Spud Count	Horizontal Spud Count	% Horizontal Spuds
CROCKETT	2	0	0%
CROSBY	0	0	0%
CULBERSON	0	0	0%
DALLAM	0	0	0%
DALLAS	0	2	100%
DAWSON	0	0	0%
DE WITT	1	64	98%
DEAF SMITH	0	0	0%
DELTA	0	0	0%
DENTON	0	28	100%
DICKENS	0	0	0%
DIMMIT	1	192	99%
DONLEY	0	0	0%
DUVAL	8	0	0%
EASTLAND	0	0	0%
ECTOR	0	0	0%
EDWARDS	1	0	0%
EL PASO	0	0	0%
ELLIS	0	0	0%
ERATH	0	0	0%
FALLS	0	0	0%
FANNIN	0	0	0%
FAYETTE	0	0	0%
FISHER	0	0	0%
FLOYD	0	0	0%
FOARD	0	0	0%
FORT BEND	3	2	40%
FRANKLIN	0	0	0%
FREESTONE	20	5	20%
FRIO	0	4	100%
GAINES	0	0	0%
GALVESTON	0	2	100%
GARZA	0	0	0%
GILLESPIE	0	0	0%
GLASSCOCK	0	0	0%
GOLIAD	3	0	0%
GONZALES	0	0	0%
GRAY	0	0	0%
GRAYSON	0	1	100%
GREGG	4	3	43%
GRIMES	1	0	0%
GUADALUPE	0	0	0%
HALE	0	0	0%
HALL	0	0	0%
HAMILTON	0	0	0%
HANSFORD	0	0	0%
HARDEMAN	0	0	0%

Table 5-2. Gas Well Completions

County	Vertical Spud Count	Horizontal Spud Count	% Horizontal Spuds
HARDIN	0	1	100%
HARRIS	5	1	17%
HARRISON	28	15	35%
HARTLEY	0	0	0%
HASKELL	0	0	0%
HAYS	0	0	0%
HEMPHILL	36	45	56%
HENDERSON	2	0	0%
HIDALGO	30	12	29%
HILL	0	0	0%
HOCKLEY	0	0	0%
HOOD	0	21	100%
HOPKINS	0	0	0%
HOUSTON	3	0	0%
HOWARD	0	0	0%
HUDSPETH	0	0	0%
HUNT	0	0	0%
HUTCHINSON	0	0	0%
IRION	2	0	0%
JACK	5	0	0%
JACKSON	7	4	36%
JASPER	0	0	0%
JEFF DAVIS	0	0	0%
JEFFERSON	1	7	88%
JIM HOGG	2	2	50%
JIM WELLS	7	0	0%
JOHNSON	0	34	100%
JONES	0	0	0%
KARNES	0	96	100%
KAUFMAN	0	0	0%
KENDALL	0	0	0%
KENEDY	2	1	33%
KENT	0	0	0%
KERR	0	0	0%
KIMBLE	0	0	0%
KING	0	0	0%
KINNEY	0	0	0%
KLEBERG	15	3	17%
KNOX	0	0	0%
LA SALLE	1	81	99%
LAMAR	0	0	0%
LAMB	0	0	0%
LAMPASAS	0	0	0%
LAVACA	10	0	0%
LEE	1	0	0%
LEON	6	4	40%
LIBERTY	3	2	40%

Table 5-2. Gas Well Completions

County	Vertical Spud Count	Horizontal Spud Count	% Horizontal Spuds
LIMESTONE	13	0	0%
LIPSCOMB	0	15	100%
LIVE OAK	7	53	88%
LLANO	0	0	0%
LOVING	0	4	100%
LUBBOCK	0	0	0%
LYNN	0	0	0%
MADISON	3	0	0%
MARION	0	1	100%
MARTIN	0	0	0%
MASON	0	0	0%
MATAGORDA	1	5	83%
MAVERICK	0	0	0%
MCCULLOCH	0	0	0%
MCLENNAN	0	0	0%
MCMULLEN	2	36	95%
MEDINA	0	0	0%
MENARD	0	0	0%
MIDLAND	0	0	0%
MILAM	0	0	0%
MILLS	0	0	0%
MITCHELL	0	0	0%
MONTAGUE	0	81	100%
MONTGOMERY	0	0	0%
MOORE	5	0	0%
MORRIS	0	0	0%
MOTLEY	0	0	0%
NACOGDOCHES	0	2	100%
NAVARRO	0	0	0%
NEWTON	1	2	67%
NOLAN	1	0	0%
NUECES	7	5	42%
OCHILTREE	1	5	83%
OLDHAM	0	0	0%
ORANGE	0	3	100%
PALO PINTO	7	1	13%
PANOLA	51	58	53%
PARKER	0	54	100%
PARMER	0	0	0%
PECOS	0	0	0%
POLK	1	0	0%
POTTER	0	0	0%
PRESIDIO	0	0	0%
RAINS	0	0	0%
RANDALL	0	0	0%
REAGAN	0	0	0%
REAL	0	0	0%

Table 5-2. Gas Well Completions

County	Vertical Spud Count	Horizontal Spud Count	% Horizontal Spuds
RED RIVER	0	0	0%
REEVES	0	12	100%
REFUGIO	11	0	0%
ROBERTS	2	9	82%
ROBERTSON	16	2	11%
ROCKWALL	0	0	0%
RUNNELS	0	0	0%
RUSK	7	22	76%
SABINE	0	0	0%
SAN AUGUSTINE	0	13	100%
SAN JACINTO	2	1	33%
SAN PATRICIO	9	6	40%
SAN SABA	0	0	0%
SCHLEICHER	0	0	0%
SCURRY	0	0	0%
SHACKELFORD	2	0	0%
SHELBY	3	9	75%
SHERMAN	5	0	0%
SMITH	0	0	0%
SOMERVELL	0	0	0%
STARR	42	5	11%
STEPHENS	18	0	0%
STERLING	0	0	0%
STONEWALL	0	0	0%
SUTTON	0	0	0%
SWISHER	0	0	0%
TARRANT	0	218	100%
TAYLOR	0	0	0%
TERRELL	0	0	0%
TERRY	0	0	0%
THROCKMORTON	3	0	0%
TITUS	0	0	0%
TOM GREEN	0	0	0%
TRAVIS	0	0	0%
TRINITY	0	0	0%
TYLER	2	3	60%
UPSHUR	0	0	0%
UPTON	0	0	0%
UVALDE	0	0	0%
VAL VERDE	0	0	0%
VAN ZANDT	0	0	0%
VICTORIA	7	0	0%
WALKER	0	0	0%
WALLER	5	0	0%
WARD	0	0	0%
WASHINGTON	0	0	0%
WEBB	22	201	90%

Table 5-2. Gas Well Completions

County	Vertical Spud Count	Horizontal Spud Count	% Horizontal Spuds
WHARTON	7	0	0%
WHEELER	30	85	74%
WICHITA	0	0	0%
WILBARGER	0	0	0%
WILLACY	4	0	0%
WILLIAMSON	0	0	0%
WILSON	0	0	0%
WINKLER	0	0	0%
WISE	2	119	98%
WOOD	0	1	100%
YOAKUM	0	0	0%
YOUNG	1	0	0%
ZAPATA	3	2	40%
ZAVALA	0	0	0%

To address the changes in the inventory as a result of the requirements of NSPS Subpart OOOO as described above, the following changes have been made to the "Gas Well Completions" tab of TCEQ's oil and gas nonpoint area source emissions estimation calculator:

- In the Basin-Level Data table: added column for flaring capture/control efficiency. Assumed a value of 95% for all basins;
- In the Basin-Level Data table: added cells for NO_x and CO flaring emission factors. The values are 0.068 and 0.37 lb/MMSCF, respectively, for all basins;
- In the County-level emissions table: added a column to show % of completions controlled (flared);
- In the County-level emissions table: modified the title in column I to read "Uncontrolled VOC Emissions (tons/event)";
- In the County-level emissions table: modified the formula in column J to reflect controls; and
- In the County-level emissions table: added columns K and L for NO_x and CO emissions.

These changes reflect the impact of the NSPS Subpart OOOO requirements on hydraulically-fractured gas well completions after October 15, 2012, which will affect the 2013 and 2014 emissions inventories as hydraulically-fractured gas wells completed after this date must be controlled with flaring. The additional calculations for NO_x and CO reflect the combustion emissions from the flare. Note that beginning January 1, 2015, hydraulically-fractured gas well completions must be conducted using reduced emissions completions or flaring. This requirement will need to be considered in future inventories.

Attachment D contains the updated TCEQ oil and gas nonpoint area source emissions estimation calculator ("ERG AppendixE_2013 with updates to Basin information.xls") reflecting the changes to the inventory for natural gas well completions as a result of the requirements of NSPS Subpart OOOO.

5.4 Pneumatic Controllers

Under the requirements of NSPS Subpart OOOO, pneumatic devices at oil and gas wells that were completed after October 15, 2012 must achieve a leak rate of six scf/hr or less. In the current inventory, the leak rate for pneumatic devices at oil wells is estimated to be less than six scf/hr for every basin. Therefore, the calculation for emissions from pneumatic devices at oil wells has not been revised.

To determine the effects on the 2013 emissions inventory of this requirement for gas wells, the percentage of affected gas wells was needed. This was determined by calculating the percent of total gas wells in production in 2013 that were completed after October 15, 2012. ERG used RRC county-level data on well counts and district level data on well completions to estimate the number of wells completed at the county level for the periods October 15, 2012 to December 31, 2012, and January 1, 2013 to December 31, 2013. ERG then calculated the percentage of new wells in each county using the county-level sum of new wells (since October 15, 2012) and the current county-level well count. This data is included in Table 5-3.

Table 5-3. New Gas Wells 10/15/12 – 12/31/13

Basin Name	2012 New Gas Wells (10/15/12 – 12/31/12)	2013 New Gas Wells	Total Gas Wells in 2013	New Wells (10/15/12 – 12/31/13) as Percent of Total
Anadarko Basin	69	526	12,036	4.9%
Bend Arch-Fort Worth Basin	275	1,425	22,388	7.6%
Eagle Ford Shale	86	1,220	11,156	11.7%
East Texas Basin/Haynesville Shale	113	340	19,931	2.3%
Palo Duro Basin	5	37	934	4.5%
Permian Basin	44	317	18,215	2.0%
Western Gulf	81	599	10,598	6.4%

Once the percentage of affected wells was known, an updated basin-weighted average bleed rate could be determined by assuming that all pneumatic devices at new wells would have a bleed rate of six scf/hr, while the bleed rates for pneumatic devices at existing wells (in existence prior to October 15, 2012) would not change. Table 5-4 presents the bleed rates for existing pneumatic devices, for new pneumatic devices (at gas wells brought into production after October 15, 2012), and the updated 2013 basin-weighted average bleed rate of all pneumatic devices within a basin.

Table 5-4. Updated Basin-Weighted Average Bleed Rate (Gas Wells)

Basin Name	Bleed Rate, Pre 10/15/2012 Devices (scf/hr/device)	Bleed Rate, Post 10/15/2012 Devices (scf/hr/device)	2013 Basin Weighted Average Bleed Rate (scf/hr/device)
Anadarko Basin	12.45	6	12.13
Bend Arch-Fort Worth Basin	6.2	6	6.18
Eagle Ford Shale	10.75	6	10.19
East Texas Basin/Haynesville Shale	17.59	6	17.33
Palo Duro Basin	8.58	6	8.46
Permian Basin	8.79	6	8.73
Western Gulf	7.78	6	7.67

As can be seen in the table, for the 2013 inventory, the average bleed rate of pneumatic devices at gas wells has slightly declined in each basin. Over time, as the percentage of wells subject to the six (scf/hr) bleed rate limitation increases, the average bleed rate of pneumatic devices will continue to decline.

In the Gas Well Pneumatic Devices tab of the TCEQ oil and gas nonpoint area source emissions estimation calculator, the column titled "Basin Bleed Rate (scf/hr)" was revised to "Basin Weighted Average Bleed Rate (scf/hr/device)" to reflect the updated bleed rates shown in Table 5-4. These changes reflect the impact of the Subpart OOOO requirements on gas well pneumatic devices at wells completed after October 15, 2012 on the 2013 emissions inventory.

Attachment D contains the updated TCEQ oil and gas nonpoint area source emissions estimation calculator ("ERG AppendixE_2013 with updates to Basin information.xls") reflecting the changes to the inventory for pneumatic controllers as a result of the requirements of NSPS Subpart OOOO.

5.5 Oil and Condensate Storage Vessels

Storage vessels are defined as a single tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water. Fuel and chemical injection tanks, skid-mounted/mobile tanks, process vessels, and pressure vessels are excluded. Subpart OOOO applies to storage tanks installed, modified, or reconstructed after August 23, 2011, having a PTE of VOC greater than or equal to six tpy, and located in the: oil and natural gas production, oil and natural gas gathering, natural gas processing, or natural gas transmission and storage segments of the industry.

Under the requirements of the rule, storage vessels are separated into two groups based on date of construction/modification. Group I storage vessels are those vessels constructed, reconstructed, or modified after August 23, 2011, and on or before April 12, 2013. The PTE of Group I storage vessels must be estimated no later than October 15, 2013. Any Group I storage vessel determined to have a PTE greater than six tpy must be in compliance with the emission standards by April 15, 2015. Therefore, for purposes of revising the 2013 inventory, no control is assumed for Group I storage tanks as controls for these tanks are not required until 2015.

Group II storage vessels are those vessels constructed, reconstructed, or modified after April 12, 2013. The PTE of Group II storage vessels must be estimated no later than thirty days after startup. Any Group II storage vessel with PTE greater than six tpy must be in compliance with the emission standards by April 15, 2014 or within 60 days after startup. Pursuant to 40 CFR 60.5365, the PTE from storage vessels can be calculated via testing or by using a generally accepted model or calculation methodology, based on the maximum average daily throughput. Note that the current TCEQ area source emissions inventory accounts for a percentage reduction due to control devices installed on existing equipment at condensate tanks. [62]

A comparison of storage vessel PTE vs. throughput, using current TCEQ area source emissions inventory emission factors for oil storage tanks (1.60 lb VOC released per barrel of oil throughput) and condensate storage tanks (3.15 – 11.02 lb VOC per barrel of throughput), shows that an oil storage tank with throughput of less than 20 bbl per day has a PTE of less than six tpy of VOC, before the effect of any controls.[63] Since the TCEQ air emissions inventory emission factors for condensate storage tanks vary by region,[64] the throughput of condensate that results in a PTE of less than six tpy varies across Texas. For example, condensate production of 2.5 bbl/day in the Western Gulf basin results in PTE of less than six tpy VOC, while condensate production of 10 bbl/day in the Anadarko basin results in PTE of less than six tpy VOC, before the effect of any controls.

Vapors that are collected and re-routed to a process do not count towards PTE. A study conducted by ERG for TCEQ in 2012 on condensate tank emissions[65] showed that many operators were installing multi-stage depressurizing devices and condensers on their wells to capture and sell that portion of their petroleum production that might have previously been lost as emissions. As these devices increase production recovery efficiency, they are not controls, so PTE would be calculated after the effect of these devices.

For any storage tank with a PTE greater than six tpy, VOC emissions must be reduced by 95% (capture + control) using either a closed vent system and a control device or a floating roof. Control devices must undergo a performance test, except for: flares that

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[62] Control factors for VOC emissions from condensate storage tanks are as follows: Anadarko basin-17.1%, Bend Arch-Fort Worth-11.8%, East Texas-10.5%, Eagle Ford Shale-46.0%, Permian-19.5%, and Western Gulf-12.2%.

[63] Based on emissions of 1.6 lb VOC per bbl oil throughput: 1.6 lb/bbl x 365 days/yr x 1 ton/2,000 lb x 20 bbl/day = 5.84 tpy of VOC.

[64] VOC emissions per bbl of condensate throughput: Anadarko basin-3.15, Bend Arch-Fort Worth-9.76, East Texas-4.22, Eagle Ford Shale-10.46, Permian-7.07, and Western Gulf-11.03. Calculation methodology is identical to that for oil.

[65] "Condensate Tank Oil and Gas Activities", Texas Commission on Environmental Quality, Air Quality Division, October 20, 2012.

are designed and operated in accordance with §60.18(b), large boilers or process heaters (> 44 megawatts), hazardous waste incinerators, or a control device that meets the performance requirements of §60.5412(a). To account for declining production, the control device can be removed from controlled storage vessels whose actual uncontrolled emissions drop to less than four tpy for more than 12 months. Control devices must also meet continuous monitoring requirements.

Since Group I storage vessels have until April 15, 2015 to comply, the effect of Subpart OOOO on emissions from these wells has not been considered for the 2013 inventory. For Group II storage vessels, the set of storage vessels that will need to be considered are those storage vessels that commenced production from April 12, 2013 through December 31, 2013. To determine the number of wells and the liquids production of the storage vessels at oil and gas production sites that were required to control emissions beginning June 11, 2013 (60 days after a date of 1st production of April 12, 2013), ERG used RRC lease-level data on oil and condensate production and TCEQ's basin-specific VOC emission factors for oil and condensate storage tanks[66],[67] to estimate the number, percentage, and liquids production of oil and gas wells completed since August 23, 2011 whose storage vessels have a PTE of VOC greater than six tpy. Although the Subpart OOOO compliance dates are different for isolated new wells and new wells located on a pad with an existing well, in doing these calculations, ERG assumed that all new wells are isolated and that production from a single well goes into a single storage tank. To simplify the determination of when a well begins production, ERG assumed that production begins on the date of completion. To simplify the determination of when a storage tank began complying with Subpart OOOO requirements, ERG assumed that storage tanks were in compliance on the date of completion.

The RRC lease-level data indicate that 2,638 new oil wells and 766 new gas wells were completed after April 12, 2013, and before January 1, 2014. Emissions calculations based on liquids production information and basin-specific emission factors for those wells described above show that 1,557 new oil wells and 356 new gas wells producing liquids are subject to the Subpart OOOO control requirements for the year 2013. The 2013 production represented by these wells (83,932,001 bbl oil and 8,636,341 bbl condensate) was compared with the total production for all new wells completed after April 12, 2013 and before January 1, 2014 (86,451,460 bbl oil and 8,719,058 bbl condensate), indicate that 97.1% of all new oil production and 99.1% of all new condensate production are subject to Subpart OOOO requirements for storage vessels.

When the 2013 oil and condensate production represented by these subject wells is compared with RRC data for 2013 statewide oil and condensate production (687,486,763 bbl oil and 107,651,266 bbl condensate), the data show that 12.2% of total

[66] "Characterization of Oil and Gas Production Equipment and Develop a Methodology to Estimate Statewide missions", TCEQ, November 24, 2010

[67] "Condensate Tank Oil and Gas Activities", TCEQ, October 10, 2012

statewide 2013 oil production and 8.02% of total statewide 2013 condensate production is subject to Subpart OOOO storage vessel control requirements. The breakdown by basin is shown in Table 5-5.

To account for these controls in the inventory, the Oil Storage Tanks tab of the TCEQ oil and gas nonpoint area source emissions estimation calculator was revised as follows:

- A new table was added with data showing the percentage of basin-level oil production that is subject to Subpart OOOO requirements for 2013;
- A new table was added showing the emission control requirements (95% control) for oil production that is subject to Subpart OOOO requirements;
- A column was added to the County-level emissions table to account for % of 2013 production controlled; and
- In the County-level emissions table, the calculations for VOC, Benzene, Toluene, Ethylbenzene, and Xylene were revised to reflect the changes in emissions due to the Subpart OOOO control requirements for emissions from storage vessels constructed after April 12, 2013.

In the Condensate Storage Tanks tab of the TCEQ oil and gas nonpoint area source emissions estimation calculator, similar changes were made. The calculation for the control percentage for each basin is complicated by the fact that a survey[68] conducted in 2012 showed that a significant percentage of statewide condensate production was already controlled. For 2012, the control factor for storage tanks that already had recovery or control devices installed ranged from 11.8% for condensate-producing gas wells in the Bend Arch-Fort Worth Basin to 46% for gas wells in the Eagle Ford Shale. Since the wells constructed in 2013 that are subject to Subpart OOOO requirements are new wells with the requirement to control emissions from storage vessels, ERG made the simplifying assumption that the percent of regional condensate production represented by these new 2013 wells would be added to the control percentage of the production that was already controlled. As required by the rule, the control percentage applied to the new subject wells is 95%.

Therefore, the Condensate Storage Tank EFs tab of the TCEQ oil and gas nonpoint area source emissions estimation calculator was revised as follows:

- The Control Factors in Table A and Table B were revised to increase the existing regional control factors by the percentages shown above (and reflecting the 95% control requirement for controlled production). These revised control factors are used in the emissions calculations in the Condensate Storage Tanks tab of the spreadsheet;
- Table C was added to show the % of total production within a basin that is subject to the NSPS control requirements; and
- A table was added to show the required NSPS control of 95%.

[68] "Condensate Tank Oil and Gas Activities", TCEQ, October 10, 2012

No revisions were needed to the Condensate Storage Tanks tab of the TCEQ oil and gas nonpoint area source emissions estimation calculator as the control factors are pulled from the Condensate Storage Tank EFs tab and inherently incorporate the NSPS Subpart OOOO control requirements.

Attachment D contains the updated TCEQ oil and gas nonpoint area source emissions estimation calculator (“ERG AppendixE_2013 with updates to Basin information.xls”) reflecting the changes to the inventory for storage vessels as a result of the requirements of NSPS Subpart OOOO.

Table 5-5. Percentage of 2013 Oil and Condensate Production Subject to Subpart OOOO Requirements

Basin	Oil			Condensate		
	Production Subject to Subpart OOOO (bbl)	Total Production (bbl)	% of Production Subject to Subpart OOOO	Production Subject to Subpart OOOO (bbl)	Total Production (bbl)	% of Production Subject to Subpart OOOO
Anadarko Basin	174,099	10,609,144	1.6%	1,066,246	14,038,374	7.60%
Bend Arch-Fort Worth Basin	787,645	20,391,120	3.9%	328,549	5,147,458	6.38%
Eagle Ford Shale	75,495,269	263,909,215	28.6%	6,493,095	68,335,461	9.50%
East Texas Basin	85,893	7,994,511	1.1%	13,158	624,895	2.11%
East Texas Basin/Haynesville Shale	76,800	6,087,890	1.3%	118,595	4,109,868	2.89%
Marathon Thrust Belt	0	5,668	0.0%	0	54,345	0.00%
Palo Duro Basin	558,642	4,124,773	13.5%	3,644	55,043	6.62%
Permian Basin	5,592,846	344,009,390	1.6%	964	2,472,622	0.04%
Western Gulf	789,990	16,494,090	4.8%	576,967	9,366,101	6.16%
Western Gulf/Beaumont-Port Arthur	13,247	2,512,043	0.5%	355	1,905,094	0.02%
Western Gulf/Houston-Galveston-Brazoria	369,936	11,348,919	3.3%	39,014	1,542,005	2.53%

6. Conclusions

ERG recommends that the TCEQ update the nonpoint area source oil and gas emissions inventory as described in this report for the following source types:

- Condensate storage tanks;
- Gas well completions;
- Gas well pneumatic devices;
- Hydraulic pump engines;
- Mud degassing (oil and gas wells); and
- Oil storage tanks.

Under the requirements of the recently revised NSPS Subpart OOOO (Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution), certain new condensate storage tanks, gas well completions, gas well pneumatic devices, and oil storage tanks require emissions control or emissions reduction strategies. Based on the findings of this study, the rule revisions have had a particularly notable impact on emissions from oil and condensate tanks due to the increase in hydrocarbon liquids production in Texas over the last few years. As new liquids production is brought on-line, particularly in areas such as the Eagle Ford Shale, storage tank control requirements are triggered such that emissions on a per barrel basis are much lower than from older wells.

For mud degassing, limited data was available to improve the current emissions estimate. This source category is not regulated; is not covered under Subpart W of the Greenhouse Gas Reporting Rule; and has not typically been considered a large emitting source. However, Texas-specific gas composition data were used to refine the estimates for mud degassing to reflect basin-specific gas composition in Texas.

Finally, updates to the input variables used to estimate emissions from hydraulic pump engines have resulted in a large increase in emissions for this category. Previously, emissions were based on input variables developed under the CenSARA 2012 emissions inventory project which reflected an average of 3.5 engines rated at 1,258 hp operating for approximately 9 hours to complete well perforation and stimulation. As shown in Table 3 above, well stimulation operations in Texas require significantly more engines, at a higher hp, and increased operational time to complete the process.

Attachment D contains an updated version of TCEQ's oil and gas nonpoint area source emissions estimation tool reflecting the revisions described above.

Attachment A

Hydraulic Pump Survey Letter

EASTERN RESEARCH GROUP, INC.

Dear [Insert Operator_Contact_Name], [Insert Operator_Contact_Title]

[Insert Operator_Company_Name] [Date]

Eastern Research Group (ERG), an independent research organization, is conducting a study on emissions from pump engines used in hydraulic stimulation and perforation activities for the Texas Commission on Environmental Quality (TCEQ). The purpose of this study is to develop equipment inventories and usage data for estimating emissions from hydraulic pump engines for each of the oil and gas producing regions in Texas. The study results will assist the TCEQ in refining the Texas air emissions inventory.

Hydraulic pump engine emissions are currently estimated by TCEQ using activity data from a 2012 Central States Air Resources Agencies (CenSARA) study. The purpose of this survey is to gather Texas-specific data on hydraulic pump engine activities so that TCEQ can refine its emissions estimates. To support this effort, the TCEQ is seeking information from Texas oil and gas drilling/hydraulic stimulation companies to assist in development of refined, county-specific equipment and usage data.

We are asking for your participation in this voluntary survey that will involve sharing information regarding the number and horsepower of engines used, and the amount of time they are used. ***Individual wells and rigs do not need to be identified.*** The information your company provides will be used for statistical purposes only in order to develop county-level and basin-level estimates and will not be republished or disseminated for other purposes. **The information you provide will be held confidential.**

ERG will contact your company via phone to discuss this effort and collect any information you are willing to share. We are seeking basin-specific hydraulic pump engine usage information for oil and gas well sites hydraulically stimulated in the [Insert Basin_name] [Insert counties_text] The specific information we are requesting for each well hydraulically stimulated in 2013:

- County
- Well type (oil or gas)
- Percent full load for engines
- Number of engines
- Horsepower of engines
- Number of fracturing stages
- Duration of each fracturing stage (hours)

A table on the reverse side of this letter shows the type of data we wish to collect.

We appreciate your assistance in this study. If you have any questions on the technical aspects of the study, please contact me at (919) 468-7902, or via email at stephen.treimel@erg.com. Completed surveys should be sent to my attention. Questions concerning the scope of this study or ERG's relationship with TCEQ may be directed to the TCEQ Project Manager, Michael Ege, at (512) 239-5706, or via email at Michael.Ege@tceq.texas.gov.

Sincerely,

Stephen Treimel, Environmental Scientist
Eastern Research Group, Inc.

Operator Name: [Insert Operator_Company_Name]
Basin and Counties: [Insert Basin_name] basin: [Insert counties_text]
Instructions: Provide the data listed below for up to ten separate well sites located in the counties listed above. To avoid biasing the survey results, we ask that you please select the well sites at random from all of the wells you worked on in this region in 2013.

Site #	County	Well type (oil or gas) [a]	Number of Engines	Horsepower of Engines	Percent Full Load for Engines (when active)	Number of Fracturing Stages	Duration of Each Fracturing Stage (hours)

[a] Does the Texas Railroad Commission consider this well a gas well (G) or an oil well (O)?

Completed surveys can be emailed to me at stephen.treimel@erg.com or printed and mailed to my attention at: Eastern Research Group, 1600 Perimeter Park Drive, Morrisville, NC 27560.

Attachment B
Mud Degassing Survey Letter

Dear [Insert Operator_Contact_Name], [Insert Operator_Contact_Title]

[Insert Operator_Company_Name] [Date]

Eastern Research Group (ERG), an independent research organization, is conducting a study on emissions from drilling mud degassing for the Texas Commission on Environmental Quality (TCEQ). The purpose of this study is to develop activity estimates for estimating emissions from mud degassing activities during well drilling for each of the oil and gas producing regions in Texas. The study results will assist the TCEQ in refining the Texas air emissions inventory.

Emissions from mud degassing are currently estimated by TCEQ using EPA default water-based mud emission factors from the Climate Registry Reporting Protocol and activity data from a 2012 Central States Air Resource Agencies (CenSARA) study. The purpose of this survey is to gather Texas-specific data on drilling mud usage, characteristics, and mud degassing activities so that TCEQ can refine its emissions estimates. To support this effort, the TCEQ is seeking information from Texas oil and gas drilling companies to assist in development of refined, county-specific equipment and usage data.

We are asking for your participation in this voluntary survey that will involve sharing information regarding the location, the type of well, the type of drilling mud used, the number of drilling days per well, and any control equipment used. ***Individual wells and rigs do not need to be identified.*** The information your company provides will be used for statistical purposes only in order to develop county-level and basin-level estimates and will not be republished or disseminated for other purposes. **The information you provide will be held confidential.**

ERG will contact your company via phone to discuss this effort and collect any information you are willing to share. We are seeking basin-specific mud degassing emissions information for oil and gas wells drilled/recompleted in the [Insert Basin_name] [Insert counties_text] The specific information we are requesting for each well drilled or recompleted in 2013:

- County
- Well type (oil or gas)
- New well or recompletion
- Type of mud used (water- or oil-based)
- Number of drilling days per well
- Are emissions from degassing equipment controlled?

A table on the reverse side of this letter shows the type of data we wish to collect.

We appreciate your assistance in this study. If you have any questions on the technical aspects of the study, please contact me at (919) 468-7902, or via email at stephen.treimel@erg.com. Completed surveys should be sent to my attention. Questions concerning the scope of this study or ERG's relationship with TCEQ may be directed to the TCEQ Project Manager, Michael Ege, at (512) 239-5706, or via email at Michael.Ege@tceq.texas.gov.

Sincerely,

Stephen Treimel, Environmental Scientist
Eastern Research Group, Inc.

Operator Name: [Insert Operator_Company_Name]

Basin and Counties: [Insert Basin_name] [Insert counties_text]

Instructions: Provide the data listed below for up to ten separate well sites located in the basin/counties listed above. To avoid biasing the survey results, we ask that you please select the well sites at random from the wells drilled in this region in 2013.

Site #	County	Well type (oil or gas) [a]	New well or Recompletion	Type of mud used (water-based, oil-based, synthetic)	Number of drilling days	Are emissions from degassing equipment controlled? (Y/N)	Percent Control (%)

[a] Does the Texas Railroad Commission consider this well a gas well (G) or an oil well (O)?

Completed surveys can be emailed to me at stephen.treimel@erg.com or printed and mailed to my attention at: Eastern Research Group, 1600 Perimeter Park Drive, Morrisville, NC 27560.

Attachment C
Survey Results
(TCEQ Hydraulic Pump Engine Study Findings.xlsx)

Attachment D
Updated Oil and Gas Nonpoint Area Source Emissions Estimation Tool
(ERG Appendix E_2013 with updates to Basin information.xlsx)