APPENDIX 8

2014 STATEWIDE DRILLING RIG EMISSIONS INVENTORY WITH UPDATED TRENDS INVENTORIES

Dallas-Fort Worth and Houston-Galveston-Brazoria Moderate Areas Reasonable Further Progress State Implementation Plan Revision for the 2015 Eight-Hour Ozone National Ambient Air Quality Standard

Project Number 2022-023-SIP-NR

2014 STATEWIDE DRILLING RIG EMISSIONS INVENTORY WITH UPDATED TRENDS INVENTORIES

FINAL REPORT

TCEQ Contract No. 582-15-50416
Work Order No. 582-15-52832-05

Prepared for:

Texas Commission on Environmental Quality
Air Quality Division

Prepared by:

Eastern Research Group, Inc.

July 31, 2015

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2014 Statewide Drilling Rig Emissions Inventory with Updated Trends Inventories

Final Report

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List of Acronyms

Acronym	Definition
AACOG	Alamo Area Council of Governments
API	American Petroleum Institute
CERS	Consolidated Emissions Reporting Schema
CO	Carbon Monoxide
DOE	U.S. Department of Energy
EIA	Energy Information Administration
ERG	Eastern Research Group
HAP	Hazardous Air Pollutant
HSE	Health, Safety and Environment
hp	Horsepower
MMBBL	Million Barrels
NEI	National Emissions Inventory
NO_x	Nitrogen Oxides
OSD	Ozone Season Daily
PM_{10}	Particulate Matter with particle diameter less than 10 micrometers
$PM_{2.5}$	Particulate Matter with particle diameter less than 2.5 micrometers
QAPP	Quality Assurance Project Plan
SCC	Source Classification Code
SCR	Silicon Controlled Rectifier
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TCAT	Texas Center for Applied Technology
TCEQ	Texas Commission on Environmental Quality
TexAER	Texas Air Emissions Repository
TOG	Total Organic Gases
RRC	Railroad Commission of Texas
TxLED	Texas Low Emission Diesel
US EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds
XML	Extensible Markup Language

1.0 Executive Summary

The purpose of this study was to develop updated, comprehensive statewide controlled and uncontrolled emissions inventories for drilling rig engines associated with onshore oil and gas exploration activities occurring in Texas. Oil and gas exploration and production facilities are some of the largest contributors to area source emissions in certain geographical areas, dictating the need for continuing studies and surveys to more accurately depict these activities. The current inventory effort builds off of two previous studies prepared for the Texas Commission on Environmental Quality (TCEQ). In 2009, Eastern Research Group (ERG) prepared a 2008 Drilling Rig Emission Inventory for the State of Texas (TCEQ, 2009), which focused exclusively on drilling activities. This effort was expanded upon in 2011 by improving the drilling activity data (including well counts, types, and depths) used to estimate emissions through acquisition of the “Drilling Permit Master and Trailer” database from the Railroad Commission of Texas (RRC) (TCEQ, 2011).

The drilling rig profiles developed in the 2009 study provided:

- The average number of engines on a rig
- Average engine model year and size in horsepower (hp)
- Average load for each engine
- Engine function (draw works, mud pumps, power)
- Average engine hour data for each well (total hours)
- Average well drilling time (actual number of drilling days)
- Average well depth

As part of this current study, a data collection effort was implemented to obtain updated drilling rig profile data focusing on a 2014 base year. In addition to development of a 2014 base year emissions inventory, trends inventories were developed to reflect emissions associated with actual annual drilling activity in Texas each year from 2012 through 2014, and for projected annual drilling activity in Texas for each year 2015 through 2040. This was accomplished by:

- conducting a review of available literature about drilling operations;
- conducting a mail, phone, and email survey of Texas oil and gas well drilling companies to obtain information on drilling rig engines used in the field in 2014;
- researching oil and gas drilling company websites to characterize the types of rigs used in the field in 2014;
- obtaining actual drilling activity data for the years 2012, 2013, and 2014;
- developing projected drilling activity for Texas for the years 2015 through 2040; and,

- developing updated drilling rig emissions profiles based on survey data obtained on the age, size, type, and operating practices of the engines used in the drilling process.

To develop updated emissions and activity data, ERG first conducted a review of available literature, looking for data on emissions from drilling rig engines that would help inform the analysis. Academic and technical literature on equipment characterization and available state and federal research on drilling rig emissions were evaluated. Additionally, ERG conducted a mail, email, and phone survey of Texas oil and gas drilling companies, requesting information on the use and type of engines used to drill oil and gas wells in Texas. Several companies were interviewed at length, to gather information on current practices and trends in the industry that are specific to Texas. This industry survey and study sought to obtain updated information to be used in conjunction with data and methodologies developed under the previous drilling rig emission inventory efforts to determine:

- equipment characteristics such as the number and type of engines used to drill wells in Texas;
- operational characteristics such as the total operating hours and load factors of the engines used to drill wells in Texas;
- updated year-specific emission factors to use for estimating emissions from drilling rig engines used in Texas;
- base year 2014 drilling activity in Texas by well type;
- historical drilling activity in Texas for the years 2012 and 2013; and
- projected drilling activity in Texas for the years 2015 through 2040.

These data were used to develop well drilling rig emissions profiles using the United States Environmental Protection Agency (US EPA)'s NONROAD emissions model.[1] ERG also gathered information from company websites and from the RigData® database to characterize the drilling rig fleet.

Target pollutants for this study include nitrogen oxides (NO_x), volatile organic compounds (VOC), carbon monoxide (CO), particulate matter (PM_{10} and $PM_{2.5}$), sulfur dioxide (SO_2), and hazardous air pollutants (HAP). Emissions were calculated for each county in Texas where drilling occurred and are provided in annual tons per year and by typical ozone season day. Emission estimates for 2012, 2013, and 2014 were based on RRC records of oil and gas well completions during those years, and U.S Department of

[1] While the NONROAD model was used to calculate drilling activity emissions (in order to more accurately capture emission standard phase in impacts), these emissions are actually classified as area sources emissions and reported as such to the TCEQ.

Energy (DOE), Energy Information Administration (EIA) oil and gas production growth estimates were used to develop the projections for the years 2015 through 2040.

The final emissions inventory estimates are provided in Consolidated Emissions Reporting System (CERS) Extensible Markup Language (XML) to facilitate entry of the data into the state's TexAER (Texas Air Emissions Repository) database, and for the purposes of submittal to US EPA. For purposes of XML preparation, Source Classification Code (SCC) 23-10-000-220 (Industrial Processes - Oil and Gas Exploration and Production - All Processes - Drill Rigs) was used, consistent with the 2009 and 2011 studies.

Table 1-1 summarizes the statewide annual criteria pollutant emission estimates for 2012 through 2040. Figures 1-1 and 1-2 present this same information in chart form for NO_x, CO, VOC, and PM_{10}. As seen in Table 1-1, $PM_{2.5}$ emissions are comparable to PM_{10} emissions, and SO_2 emissions are less than 25 tons per year for all study years. Appendix A provides a complete summary of emissions of all pollutants (including HAPs) for all years.

Table 1-1. Statewide Drilling Rig Estimates (Tons/Year)

Year	CO	NO_x	$PM_{2.5}$	PM_{10}	SO_2	VOC
2012	8,566	41,724	1,221	1,259	16	2,068
2013	7,826	38,167	1,115	1,149	15	1,890
2014	11,278	36,488	1,176	1,213	20	3,249
2015	12,173	38,629	1,269	1,308	22	3,524
2016	12,110	38,934	1,191	1,228	22	3,501
2017	12,423	38,842	1,229	1,267	23	3,528
2018	7,598	39,456	951	980	23	2,419
2019	4,098	31,423	477	492	20	2,479
2020	3,709	31,090	448	462	20	2,466
2021	3,681	30,855	445	459	20	2,448
2022	3,661	27,011	443	456	20	2,434
2023	1,940	26,492	339	349	20	2,026
2024	1,481	25,645	309	318	19	1,938
2025	1,469	25,448	306	316	19	1,923
2026	1,434	24,944	301	310	19	1,886
2027	1,419	24,683	298	307	19	1,867
2028	1,408	24,499	295	305	19	1,853
2029	1,398	24,042	290	299	18	1,838
2030	1,368	23,611	285	294	18	1,809
2031	1,332	22,758	271	279	18	1,761
2032	1,299	22,192	264	272	17	1,717
2033	1,272	21,709	258	266	17	1,682

Table 1-1. Statewide Drilling Rig Estimates (Tons/Year)

Year	CO	NO_X	$PM_{2.5}$	PM_{10}	SO_2	VOC
2034	1,138	20,924	237	244	17	1,623
2035	1,119	20,587	233	240	16	1,597
2036	1,110	20,415	231	238	16	1,583
2037	1,101	20,042	228	235	16	1,568
2038	1,098	19,989	227	234	16	1,564
2039	987	19,802	212	218	16	1,554
2040	984	19,755	211	218	16	1,550

Figure 1-1. Statewide Drilling Rig Estimates (NO_X and CO Tons/Year)

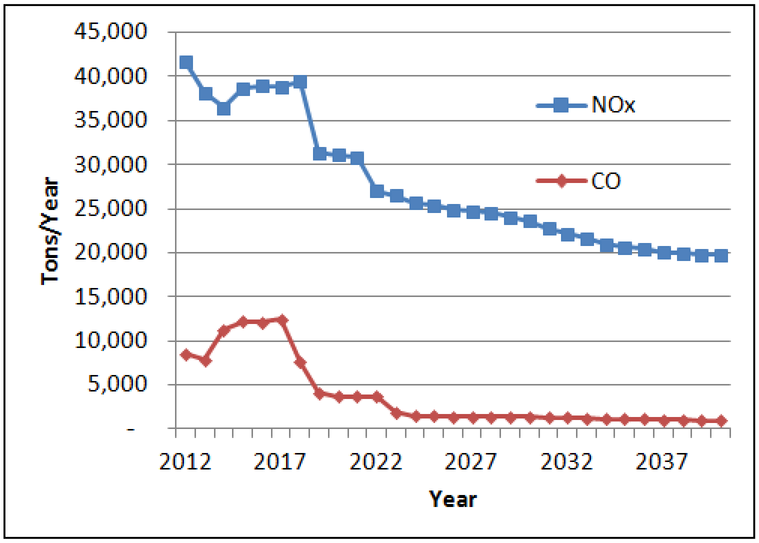
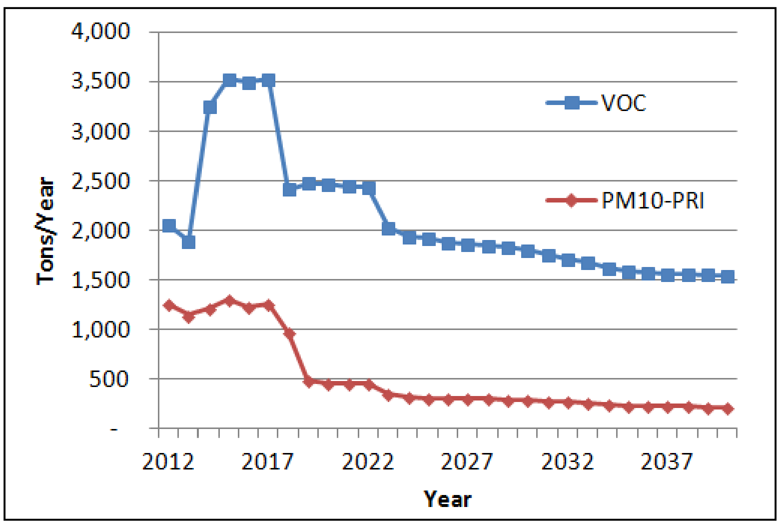


Figure 1-2. Statewide Drilling Rig Estimates (VOC and PM_{10} Tons/Year)



The study results expand upon the 2009 and 2011 efforts by updating the emission factors using equipment profile data representative of field operations in 2014. The result is an updated, temporally resolved profile of county-level drilling activity emissions.

Based on the projected oil and gas production levels in Texas from the EIA, drilling activity is estimated to generally increase across the state through the next 15 to 20 years before returning to 2014 levels. However, the continued phase-in of more stringent Non-Road diesel engine emission standards as older engines are replaced with new engines should cause a steady decrease in drilling-related emissions per unit of activity (feet drilled) over time. SO_2 emissions levels in particular are estimated to have fallen substantially due to the introduction of the ultra-low sulfur standards for diesel fuel in effect since 2010, and should remain low for the foreseeable future.

An analysis of county-level data found that the vast majority of Texas counties produced some level of emissions associated with drilling activities (180 of 254 counties) in the 2014 base year. However, the county-level distribution of NO_x emissions is highly skewed, with 10 counties being responsible for 50 percent of total statewide drilling rig NO_x emissions in 2014. The preponderance of the high NO_x emitting counties are located in West and South-Central Texas. These areas correspond to the high level of oil and gas exploration activities in the Permian Basin and the Eagle Ford Shale areas, respectively.

While the emissions inventory results provide an excellent basis for assessing historical emissions levels, projections of future activity are highly uncertain, and subject to significant fluctuations in activity depending upon economic factors and associated oil and gas prices. Accordingly, periodic refinement of the drilling activity data used for projected years 2015 through 2040 is strongly recommended to account for such factors.

2.0 Introduction

The purpose of this study was to develop updated, comprehensive, statewide controlled and uncontrolled emissions inventories for drilling rig engines associated with onshore oil and gas exploration activities occurring in Texas. Oil and gas exploration and production facilities are among the largest contributors to area source emissions in certain geographical areas, warranting continuing studies and surveys to more accurately depict these activities. While drilling activities are generally short-term in duration, typically spanning a few weeks to a few months, the associated diesel engines are usually very large in size. As such, drilling activities can generate substantial amounts of NO_x emissions.

The current inventory effort builds off of two previous studies prepared for the TCEQ. In 2009, ERG prepared a 2008 Drilling Rig Emission Inventory for the State of Texas (TCEQ, 2009), which focused exclusively on drilling activities. This effort was expanded upon in 2011 by improving the drilling activity data (including well counts, types, and depths) used to estimate emissions through acquisition of the “Drilling Permit Master and Trailer” database from the RRC (TCEQ, 2011).

To develop updated emissions and activity data, ERG first conducted a review of available academic and technical literature on equipment characterization and available state and federal research on emissions from drilling rig engines that would help form the analysis. Additionally, ERG conducted a mail, email, and phone survey of Texas oil and gas drilling companies, requesting information on the use and type of engines used to drill oil and gas wells in Texas. Several companies were interviewed at length, to gather information on current practices and trends in the industry that are specific to Texas. This information was then used to develop updated emission factors for each rig and well type. Finally, emissions were calculated on a county-level basis and provided in annual tons per year and by typical ozone season day.

Section 3.0 of this report provides an overview of the drilling process and identifies the types of activities and equipment that are commonly associated with drilling activity. Section 4.0 presents a summary of the literature and database review that was conducted to identify current studies and data that may be useful in the compilation of the Texas drilling rig emissions inventory. Section 5.0 describes the industry survey that was implemented to obtain updated drilling rig activity and equipment characterization data representative of operations in Texas in 2014, and Section 6.0 describes how that data was used to develop updated emission factors for drilling rig engines for the years 2012 through 2040. Section 7.0 describes the development of the emissions inventory including how the activity data was compiled, how the model drilling rig emission profiles were developed, and how these model drilling rig emission profiles were combined with the activity data to develop the emission inventories, along with quality assurance measures applied. Section 8.0 summarizes the study conclusions and offers recommendations for future studies.

3.0 Drilling Rig Overview

Air pollutant emissions from oil and gas drilling operations originate from the combustion of diesel fuel in the drilling rig engines. The main functions of the engines on an oil and gas well drilling rig are to provide power for hoisting pipe, circulating drilling fluid, and rotating the drill pipe. Of these operations, hoisting and drilling fluid circulation require the most power.

There are two common types of drilling rigs currently in use – mechanical and electrical. In general, mechanical rigs have three independent sets of engines. The first set of engines (draw works engines) are used to provide power to the hoisting and rotating equipment, a second set of engines (mud pump engines) are dedicated to circulating the drilling fluid which is commonly referred to as "mud", and a third set of engines (generator engines) are used to provide power to auxiliary equipment found on the drill site such as lighting, heating, and air conditioning for crew quarters and office space. There may be one, two, or more draw works engines, depending on the input power required. There are typically two mud pumps for land rigs, with each mud pump independently powered by a separate engine. The mud pump engines are typically the largest engines used on a mechanical rig. Finally, there are typically two electric generator engines per mechanical rig, with one running continuously and the second serving as a stand by unit.

Electrical rigs are typically comprised of three large, identical diesel-fired engine-generator sets that provide electricity to a control house called a silicon controlled rectifier (SCR) house. Electricity from the SCR house is then used to provide power to separate motors on the rig. In this configuration, there are dedicated electric motors used for the draw works/hoisting operations, the mud pumps, and other ancillary power needs (such as lighting). The generator engines are loaded as required to meet fluctuating power demands, with one unit typically designated for standby capacity. The trend in new rig design is almost exclusively towards electric rigs. This is probably due to the relative expense of engines versus motors, both in terms of initial cost and maintenance. Today, electrical rigs are common, especially for larger rigs (Bommer, 2008).

Oil and gas wells are commonly classified as vertical, directional, or horizontal wells, depending on the direction of the well bore. Vertical wells are historically the most common, and are wells that are drilled straight down from the location of the drill rig on the surface. Directional wells are wells where the well bore has not been drilled straight down, but has been made to deviate from the vertical. Directional wells are drilled through the use of special tools or techniques to ensure that the well bore path hits a particular subsurface target, typically located away from (as opposed to directly under) the surface location of the well. Horizontal wells are a subset of directional wells, but are distinguished from directional wells in that they typically have well bores that are initially vertical, but at some depth begin to deviate from vertical by 80 - 90 degrees. Horizontal wells are commonly drilled in shale formations. Once the desired depth has been reached (the well bore has penetrated the target formation), lateral legs are drilled to provide a greater length of well bore in the reservoir.

4.0 Literature and Database Review

At the start of this study ERG conducted a review of relevant literature, current studies, and available data that could be used in the development of an updated drilling rig engine emissions inventory for Texas. The results of this research are discussed below.

4.1 RigData® Database

In order to survey drilling rig contractors and oil and gas operators across the state, ERG purchased a commercial database that contained contact information for companies that were active in well drilling activities occurring in Texas in 2014 (RigData®). This database contained contact information including name, address, and phone number for over 150 drilling companies that drilled over 20,000 wells in 2014. This database provided the necessary data to implement the survey mail out.

In addition to the drilling company contact information, the RigData® database also contained information on the type of well drilled (vertical, directional, or horizontal), the well depth, the spud date (date drilling commenced), and the rig release date (when the rig was released from the well). This information was useful to supplement the information obtained during the survey effort. In particular, the well depth and temporal data allowed an independent estimation of the hours needed to drill a well, in terms of hour per 1,000 feet drilled. This is discussed below.

4.2 Drilling Company Websites

Many of the larger drilling contractors provide detailed information about their drilling rig fleets on-line. Examples of these websites were provided in the approved Data Collection Plan. ERG reviewed this on-line information in an effort to gain a better understanding of typical drilling rig engine profiles, including the size, number, and type of engines used on typical rigs. Additional information provided included the type of rig (mechanical or electric).

When combined with data from RigData®, an estimate of the breakdown of rig type by well category (horizontal wells; deep vertical wells greater than 7,000 feet deep; and shallow vertical wells less than 7,000 feet deep) was possible. This analysis showed that 96% of shallow vertical wells (< 7,000 feet) are drilled by mechanical rigs, while 86% of horizontal wells are drilled by electrical rigs. 80% of deep vertical wells (> 7,000 feet) are drilled by mechanical rigs. These breakdowns were used to develop composite emission factor profiles for each well type as discussed in Section 6.1.3.

4.3 EPA Nonpoint Oil and Gas Emission Estimation Tool

EPA recently developed a Nonpoint Oil and Gas Emission Estimation Tool (EPA Tool) used to supplement the 2011 National Emissions Inventory (NEI)[2] by providing area source emissions estimates for upstream oil and gas processes where such data is not provide by the states. The EPA Tool covers a variety of upstream emissions processes, including drilling rig engines.

Data contained within the EPA Tool that is used to estimate emissions from drilling rig engines was evaluated for comparison to data collected during the survey process. This data includes the number and size of drilling rig engines, and the load at which these engines were operated during the drilling process. The results of this comparison are discussed in more detail below.

4.4 Oil and Gas Emission Inventory, Eagle Ford Shale

The Alamo Area Council of Governments (AACOG), published a study in April, 2014 entitled “Oil and Gas Emission Inventory, Eagle Ford Shale” (AACOG, 2014). 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 activity data on production, drill rig counts, well counts, well characteristics, and nonroad equipment from the Railroad Commission of Texas, Schlumberger, Baker-Hughes, TCEQ, oil and gas companies, and previous studies to get a comprehensive view of the type and amount of equipment used in the area. The study then combined this activity data with emissions factors from a variety of sources, including TCEQ’s 2011 Drilling Rigs Emission Inventory study (TCEQ, 2011), equipment manufacturers, and the results of Texas Center for Applied Technology (TCAT) surveys to develop an air emissions inventory for oil and gas operations in the Eagle Ford Shale region. The study also examined development trends in the region, and, based on predicted regional production increases in the future, developed estimates of air emissions for the years 2015 and 2018 under three different development scenarios[3].

Relevant information from the AACOG study has been evaluated for use and compared to information obtained from other sources to assist in development of the state-wide

[2] Information on the 2011 National Emissions Inventory, including EPA’s Nonpoint Oil and Gas Emission Estimation Tool, is available online at: http://www.epa.gov/ttnchie1/net/2011inventory.html

[3] 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.

2014 drilling rig inventory. In particular, the AACOG study has data on the number and size of engines used in each rig type, as well as the typical drilling rate (feet/hour). The information from the AACOG study is compared to the data obtained during the drilling rig engine survey in more detail below. It should be noted that as of July, 2015, an updated version of this report is pending and should be considered in any future inventory efforts.

4.5 EIA Annual Energy Report

The US Department of Energy (DOE) Energy Information Administration (EIA) has published projections of oil and gas production for the Southwest and Gulf Coast regions in their Annual Energy Outlook 2015, with projections to 2040 report (EIA, 2015). The EIA data was used to estimate oil and gas well drilling activity for the years 2015 through 2040.

5.0 Drilling Rig Engine Survey

5.1 Survey Implementation

In order to survey drilling rig contractors and oil and gas operators across the state, the drilling rig engines survey targeted oil and gas well drilling companies and attempted to obtain information on the size, number, and type of drilling rig engines used on their drilling rigs, as well as standard operating practices. The companies targeted had significant activity drilling oil and gas wells in Texas in 2014. Contact information for each company was obtained through purchase of the RigData® dataset. The survey effort itself focused on collecting the following information from each respondent:

- The number of engines on a rig;
- Engine make, model, model year, and size (hp);
- Average load for each engine;
- Engine function (draw works, mud pumps, generators);
- Actual fuel use data for each well (total fuel use);
- Total well drilling time (actual number of drilling days);
- Well depth; and
- Number of wells represented by the survey.

Using the contact information, ERG began implementing the Data Collection Plan on March 19, 2015 and collected data through June 5, 2015. ERG initiated the survey by mailing survey letters to the drilling companies on a staggered four week timeline, beginning with the larger drillers. Appendix B contains a copy of the survey letter and form used to solicit drilling rig information from the target respondents.

The largest companies were contacted first to allow for the time necessary in these larger organizations for the survey to work its way through their organizational structure. This initial mail out was followed up with subsequent mailings on a weekly basis to the medium and small drillers in weeks two through five.

Within one week of the first mail out, the target respondents were contacted by phone, asked if they had received the survey, and given a summary of the project and were asked if they were willing to participate. The same procedure was followed in consecutive weeks until all the target respondents had been contacted. As a result of this strategy, by the end of week five almost all the respondents had been contacted by mail, phone and email at least once each.

In order to make the survey as user-friendly as possible, it was submitted to each target respondent using three different formats: a self-addressed stamped envelope, a customized spreadsheet attached with the cover letter in an email, and through a link to an electronic survey that could be filled out online using Google Forms.

Typically, when calling the company and asking for the original contact, the office manager or secretary would ask the purpose of the call, a short summary of the project would be given, and a contact would be assigned based on the conversation. If the contact was different than the one listed in the original dataset, an email address was requested and a letter modified to fit the new contact was emailed to the new recipient. This was typically done after either a direct phone contact or a voice mail was left with the updated contact.

Frequently the person (or multiple persons in the case of the larger drillers) on the contact list was not the individual authorized to complete a survey. Because the lists are public information and the drillers are frequently contacted for commercial sales purposes, the initial contact was often only able to provide direction as to where in their company the phone call should be directed.

In the case of the larger companies, the contact listed in the RigData® dataset was typically a drilling superintendent or an area manager who was not authorized to give out the requested data. In those cases we were directed to the appropriate corporate contact for this survey. Usually that person was an executive of some sort in the company's Health, Safety and Environment (HSE) department. The corporate process usually consisted of the HSE contact asking the Operations department for the data and waiting for the decision to participate in the survey to come down the corporate chain of command.

The process worked similarly for smaller companies, however the chain of command tended to be shorter and usually the correct contact was identified much faster. For the smallest companies, the contact in the RigData® dataset was often determined to be the correct contact with authority to complete the survey.

Since the original mail-out was staggered along a four week timeline, the contact strategy came from the timing of the mail-out and the nature of the corporate bureaucracy of the target company. After initial contact, follow up communication was made with each company on a rolling basis for the rest of the survey period.

The voluntary nature of the survey dictated that we attempt to contact the respondents in a way designed to remind them of the survey, but without antagonizing them to the point of non-participation. In order to do this efficiently, an email tracking software was used to determine when and if the emails were being opened.

The level of contact with each company was dictated based on the response of the contacts. If the contacts were opening the email on a regular basis a note was made of that and an appropriate calendar date was set to check back with them by phone. If they were not opening the email, a response date was setup to automatically return the email sooner and trigger a phone call in order to leave a message or a voice mail.

After the original mail-outs had been distributed, it was decided to expand the contact list in an attempt to collect more data. As a result, a supplemental distribution list was developed that included additional small and medium drilling companies. The supplement survey was distributed to the target respondents, and then each target respondent was called and emailed in much the same fashion as the original contact list.

Each driller was contacted at least five times by mail, phone and email, and the larger drillers were contacted 10-15 times over the eight week collection period.

During the last two weeks of the survey, any driller who had previously not responded was sent an email in the morning and called that day to reinforce the contact and remind them of the due date and ask for their participation.

Ultimately, over 200 individuals at 139 different companies were contacted. Upon follow-up to the survey mail out, it was determined that several of these companies were no longer in business, and several others drilled water wells and were not involved in the drilling of oil or gas wells. Table 5-1 presents the final disposition of response to the survey for each of these companies.

Table 5-1. Survey Statistics

Survey Activity/Results	Number of Respondents
Attempted Company Contacts	139
Refusal to Participate	27
Soft Refusal (did not return attempted contacts via phone calls or email)	102
Respondent Interviewed and provided sufficient data for inclusion in inventory dataset	10

5.2 Survey Response Summary

The surveys that were received were generally complete and deemed to be representative of oil and gas well drilling operations in Texas in 2014. The surveys deemed complete for inclusion in the inventory were from 9 different companies that drilled over 1,000 wells in Texas in 2014. These wells were located in all of the major oil and gas regions in the state (East Texas, Ft. Worth/Bend Arch, Permian, Eagle Ford, and the Western Gulf). One additional survey was received that did not contain sufficient information to be included in the analysis. Updated 2014 drilling rig profiles for three different well categories were developed based on the survey data received, and

Table 5-2 presents the final drilling rig profiles that will be used in this inventory project. Appendix C contains the survey results by well category.

Table 5-2. 2014 Final Drilling Rig Profiles Obtained From Current Survey

Well Category	Rig Type	Engine Type	# of Engines	Average Age (yrs)	Engine Size (hp)	Hours per 1,000 feet	Average Load (%)
Horizontal	Electric	All [a]	3.00	2.50	1,338.00	33.93	60.00
Vert > 7,000	Mechanical	Drawworks	2.00	8.00	597.79	28.85	70.00
Vert > 7,000	Mechanical	Mud Pump	2.00	7.74	1,093.51	24.39	63.33
Vert > 7,000	Mechanical	Generator	2.00	8.10	655.57	18.86	86.67
Vert < 7,000	Mechanical	Drawworks	1.70	23.10	430.18	26.13	43.49
Vert < 7,000	Mechanical	Mud Pump	2.68	9.11	614.61	22.16	42.21
Vert < 7,000	Mechanical	Generator	1.96	27.86	279.69	21.41	80.38

[a] Electric rigs use a single bank of engines to power all equipment on the rig.

5.3 Survey Comparison to Other Available Data

Tables 5-3 through 5-5 present a comparison of the updated 2014 drilling rig profiles with other available data for the three well categories: horizontal wells, vertical wells deeper than 7,000 feet, and vertical wells shallower than 7,000 feet, respectively. The comparison data was obtained from the references discussed above, including the 2009 TCEQ survey (TCEQ, 2009), data contained within the RigData® data set, the 2014 AACOG study (AACOG, 2014), and the EPA Tool.

Table 5-3 below compares the drilling rig profiles for horizontal wells obtained from the current survey with the same data obtained from the 2009 TCEQ drilling rig survey, the AACOG Study, and the EPA Tool.

Table 5-3. Data Comparison: Horizontal Wells

Study Reference	Rig Type	Engine Type	# of Engines	Average Age (yrs)	Engine Size (hp)	Hours per 1,000 feet	Average Load (%)
Current Survey [a]	*Electric*	*All [b]*	*3.00*	*2.50*	*1,338*	*33.93*	*60.0*
2009 TCEQ Survey	Electric	All [b]	2.03	2.00	1,346	47.30	52.5
EPA Tool	Electric	All [b]	3.00	NA[c]	1,500	NA[c]	NA[c]
2014 AACOG Study	Electric	All [b]	3.17	NA[c]	1,429	20.40	NA[c]
RigData® Dataset	Electric	All [b]	NA[c]	NA[c]	NA[c]	45.39	NA[c]

[a] This is the data obtained from the current (2015) survey.

[b] Electric rigs use a single bank of engines to power all equipment on the rig.

[c] Not Available.

Of note in Table 5-3 is the reduction in the estimate of the time required to drill a well per unit depth (as reflected in the "Hours per 1,000 feet" column) from the 2009 TCEQ survey. The AACOG study was conducted in 2013, and it notes that "New drill rigs and improved technology reduces the time it take to drill 1,000 feet compared to what was report in ERG's (2009) drill rig emission inventory." The current survey data results shown in Table 5-3 (33.93 hours per 1,000 feet drilled) appear to confirm this observation, which could be attributable in part to the increased load factors.

Table 5-4 below compares the drilling rig profiles for deep vertical wells obtained from the current survey with the same data obtained from the 2009 TCEQ drilling rig survey, the AACOG Study, and the EPA Tool.

Table 5-4. Data Comparison: Vertical Wells Deeper than 7,000 Feet

Study Reference	Rig Type	Engine Type	# of Engines	Average Age (yrs)	Engine Size (hp)	Hours per 1,000 feet	Average Load (%)
Current Survey	*Mechanical*	*Drawworks*	*2.00*	*8.00*	*597.79*	*28.85*	*70.00*
		Mud Pump	*2.00*	*7.74*	*1093.51*	*24.39*	*63.33*
		Generator	*2.00*	*8.10*	*655.57*	*18.86*	*86.67*
2009 TCEQ Survey	Mechanical	Drawworks	2.01	25.00	455.00	35.90	47.40
		Mud Pump	1.62	18.00	761.00	33.20	46.00
		Generator	2.00	10.00	407.00	19.30	78.70
EPA Tool	Mechanical	Drawworks	1.25	NA[a]	647.00	NA[a]	54.00
		Mud Pump	1.75	NA[a]	601.00	NA[a]	59.00
		Generator	1.33	NA[a]	402.00	NA[a]	68.00
RigData® Dataset	Mechanical	(All)	NA[a]	NA[a]	NA[a]	40.03	NA[a]
AACOG Study	Mechanical	(All)	5.88	NA[a]	702.00	20.40	NA[a]

[a] Not available.

Based on the data shown in Table 5-4, the cumulative horsepower employed by drilling rigs used to drill a deep, vertical well is 4,694 based on the current survey data as compared to 2,961 cumulative horsepower in the 2009 study. The current survey data compares favorably with the data from the AACOG study, which shows a cumulative horsepower requirement of 4,128 for wells drilled using mechanical rigs. The data in the EPA Tool is lower (at 2,395 cumulative horsepower), but the EPA Tool does not distinguish drilling rig engine requirements by well depth. As with the updated data for Horizontal wells, the current survey data for the deeper vertical wells shows a reduction in the estimate of the time required to drill a well per unit depth (as reflected in the "Hours per 1,000 feet" column) from the 2009 TCEQ survey. For these types of wells, it appears that the newer rigs utilize both more horsepower, and higher load factors to improve efficiency.

Table 5-5 below compares the drilling rig profiles for shallow vertical wells obtained from the current survey with the same data obtained from the 2009 TCEQ drilling rig survey, the AACOG Study, and the EPA Tool.

Table 5-5. Data Comparison: Vertical Wells Shallower than 7,000 Feet

Study Reference	Rig Type	Engine Type	# of Engines	Average Age (yrs)	Engine Size (hp)	Hours per 1,000 feet	Average Load (%)
Current Survey	*Mechanical*	*Drawworks*	*1.70*	*23.10*	*430.18*	*26.13*	*43.49*
		Mud Pump	*2.68*	*9.11*	*614.61*	*22.16*	*42.21*
		Generator	*1.96*	*27.86*	*279.69*	*21.41*	*80.38*
2009 TCEQ Survey	Mechanical	Drawworks	1.6	7	442	30.8	51.8
		Mud Pump	1.69	6	428	29.4	45.9
		Generator	0.97	4	330	28.3	70.4
EPA Tool	Mechanical	Drawworks	1.25	NA[a]	647.00	NA[a]	54.00
		Mud Pump	1.75	NA[a]	601.00	NA[a]	59.00
		Generator	1.33	NA[a]	402.00	NA[a]	68.00
RigData®	Mechanical	(All)	NA[a]	NA[a]	NA[a]	36.64	NA[a]
AACOG Study	Mechanical	(All)	5.88	NA[a]	702.00	20.40	NA[a]

[a] Not available.

As shown in Table 5-5, the cumulative horsepower employed at a shallow, vertical well is 2,928 based on the current survey data as compared to 1,751 cumulative horsepower in the 2009 study. Neither the AACOG study nor the EPA Tool distinguish drilling rig engine requirements by well depth, so the values used in those studies (4,128 and 2,395 cumulative horsepower, respectively) are the same in Tables 5-4 and 5-5. As would be expected, the current survey data shows a lower power requirement for drilling shallow wells than is needed for the deeper wells. As with the updated data for Horizontal and deep Vertical wells, the current survey data for the shallow vertical wells shows a reduction in the estimate of the time required to drill a well per unit depth (as reflected in the "Hours per 1,000 feet" column) from the 2009 TCEQ survey.

6.0 Emissions Factor Development

The survey data described in the previous section were used to develop "Model Rig" engine profiles. These profiles were in turn used to provide inputs for emission factor modeling using EPA's NONROAD model. The resulting NONROAD model outputs provide emission factors specific to each model rig profile of interest, expressed in terms of tons of pollutant per 1,000 feet drilled. The process used to develop the emission factors is described in detail below.

6.1 Model Rig Engine Profiles

As described above, updated drilling rig engine profiles for three distinct model rig categories were developed for the following well types and depths based on the results of the data collection survey:

- Mechanical Rigs drilling Vertical wells less than or equal to 7,000 feet;
- Mechanical Rigs drilling Vertical wells greater than 7,000 feet; and
- Electric Rigs.

For each of these categories, an updated model rig engine profile was developed. In order for the model rig engine profile data to be applied consistently to the RRC activity data, the survey results were normalized to a 1,000 foot drilling depth. This was accomplished by dividing the total drilling hours for each engine included in each survey by the well depth for that survey to obtain the hours of operation per engine per 1,000 feet of drilling depth.

The following average engine parameters were calculated for each model rig well type category using a weighted average for each parameter based on the number of wells associated with each survey:

- Number of engines by rig type (i.e., mechanical draw works, mud pumps, and generators; and electrical rig engines)
- Engine age
- Engine size (hp)
- Engine on-time (hours/1,000 feet drilled)
- Overall average load (%)

The updated weighted average engine parameters developed for each model rig category by rig type are summarized in Table 6-1.

Table 6-1. Model Rig Engine Parameters

Well Category	Rig Type	Engine Type	# of Engines	Average Age (yrs)	Engine Size (hp)	Hours per 1,000 feet	Average Load (%)
Horizontal	Electric	All [a]	3.00	2.50	1,338.00	33.93	60.00
Vert > 7,000	Mechanical	Drawworks	2.00	8.00	597.79	28.85	70.00
Vert > 7,000	Mechanical	Mud Pump	2.00	7.74	1,093.51	24.39	63.33
Vert > 7,000	Mechanical	Generator	2.00	8.10	655.57	18.86	86.67
Vert < 7,000	Mechanical	Drawworks	1.70	23.10	430.18	26.13	43.49
Vert < 7,000	Mechanical	Mud Pump	2.68	9.11	614.61	22.16	42.21
Vert < 7,000	Mechanical	Generator	1.96	27.86	279.69	21.41	80.38

[a] Electric rigs use a single bank of engines to power all equipment on the rig.

6.2 Model Rig Emission Factors

Using the model rig engine parameters presented in Table 6-1, EPA's NONROAD2008a model was run to develop criteria pollutant emission factors for each of the three model rig types, for each year (2012 through 2040). Note the NONROAD model accounts for expected emission reductions over time due to the phasing in of EPA's emissions standards for nonroad diesel engines.[4] An additional set of emission factors were also developed for an "uncontrolled" scenario representing emissions from equipment prior to any EPA nonroad diesel engine standards (discussed below).

EPA's NONROAD emission factor model estimates emissions for "Other Oil Field Equipment" which includes fracturing rigs, mechanical drilling engines, oil field pumps, pump jacks, and seismograph rigs (PSR 1998). Of these subcategories, only the first three are involved in drilling activities. The survey results successfully profiled activity and population levels for drilling engines and pumps, as well as electrical generators used to power auxiliary equipment.

Following the same methodology used in the 2011 emission inventory study, ERG modified the ACTIVITY.DAT file within NONROAD to reflect the appropriate hours per thousand feet of drilling, and engine load factors, for the required engine types (mechanical and electrical engines) for each of the rig types as appropriate. Modifications were made for SCC 2270010010 (Diesel Other Oil Field Equipment) resulting in seven unique ACTIVITY.DAT files.

[4] While the NONROAD model was used to calculate drilling activity emissions (in order to more accurately capture emission standard phase in impacts), these emissions are actually classified as area sources emissions and reported as such to the TCEQ.

ERG also modified NONROAD's TX.POP file to reflect the appropriate average hp for the engine type in question, and set the equipment population count to one for the corresponding hp bin, and zero for all other hp bins, in order to facilitate post-processing calculations.

Next, default NONROAD OPT files (input files containing basic model run information) were modified to reflect the statewide diesel fuel sulfur levels (see Table 6-4 below) for each scenario year of interest. Accordingly, sets of OPT, activity, and population files were developed to model each well type/engine type/scenario year combination for this analysis.

HAP emission factors were developed by speciating the NONROAD criteria emission outputs based on HAP emissions profiles obtained from the EPA National Mobile Inventory Model (EPA, 2015) and the California Air Resource Board's Speciation Profile Database (ARB, 2001). The specific ARB speciation profile used for Manganese, Mercury, and Nickel is Profile #425 for PM. This methodology is consistent with the prior 2011 emission inventory study approach. The specific HAP speciation factors used are presented in Table 6-2 and Table 6-3.

Table 6-2. PM_{10} Speciation Factors

HAP	HAP CAS #	Weight Fraction of PM_{10}
Acenaphthene	83329	0.0001
Acenaphthylene	208968	0.000084
Anthracene	120127	0.00000043
Arsenic & compounds	7440382	0.000038866
Benz(a)anthracene	56553	0.00000071
Benzo(a)pyrene	50328	0.00000035
Benzo(b)fluoranthene	205992	0.00000049
Benzo(g,h,i)perylene	191242	0.00000019
Benzo(k)fluoranthene	207089	0.00000035
Chrysene	218019	0.0000019
Dibenzo(a,h)anthracene	53703	2.9E-09
Fluoranthene	206440	0.000017
Fluorene	86737	0.0001
Indeno(1,2,3,c,d)pyrene	193395	0.000000079
Naphthalene	91203	0.00046
Phenanthrene	85018	0.00026
Pyrene	129000	0.0000029
Manganese [a]	7439965	0.00004
Mercury [a]	7439976	0.00003
Nickel [a]	7440020	0.000019

[a] Based on ARB Profile #425.

Table 6-3. VOC Speciation Factors

HAP	HAP CAS #	Weight Fraction of VOC
1,3-Butadiene	106990	0.0018616
2,2,4-Trimethylpentane	540841	0.000719235
Acetaldehyde	75070	0.05308
Acrolein	107028	0.00303165
Benzene	71432	0.020344
Ethyl Benzene	100414	0.0031001
Formaldehyde	50000	0.118155
Hexane	110543	0.0015913
Propionaldehyde	123386	0.0118
Styrene	100425	0.00059448
Toluene	108883	0.014967
Xylene	1330207	0.010582

SO_2 emissions are based on the diesel fuel sulfur content, provided in weight percent in the NONROAD input files. Diesel sulfur values were calculated on a statewide basis for all scenario years. Statewide averages were calculated by weighting the county-specific sulfur weight percent values in TCEQ's TexN model by the total drilling depth for each county for the same year. Table 6-4 summarizes the resulting diesel fuel sulfur levels for each scenario year. Note that 1990 corresponds to the uncontrolled scenario noted above.

Table 6-4. Diesel Fuel Sulfur Content (% wt), Statewide Weighted Average

Year	Sulfur Content (% wt)
1990	0.30407
2012	0.00052
2013	0.00052
2014+	0.00055

The NONROAD model outputs provide mass emissions for each engine and rig type, for each calendar year of interest. The activity levels entered into NONROAD corresponded to the hours required to drill 1,000 feet, so the associated mass emission outputs are uniformly expressed in terms of thousand feet drilled. Total emissions for each engine/drill rig category combination were then calculated by dividing the mass emissions outputs by the fractional engine population for the appropriate engine model year (using NONROAD's by-model-year output option), and then multiplying by the average number of engines for each drill rig type. The resulting value for a given pollutant represents an emission factor expressed in mass per 1,000 feet drilled.[5]

To illustrate the emission factor calculation process, consider shallow well mechanical draw works engines. The average age for these engines is 23 years. Therefore, for the 2014 calendar year, emissions for a 23 year old (1991 model year) engine are first identified in the NONROAD by-model-year output. Since the NONROAD population file was set to equal one unit (the sum across all engine model years), NONROAD calculates the "population" of 23 year old engines to be 0.0279 (i.e., 2.79% of all engines operating in 2014).[6] In order to calculate total emissions per 1,000 feet of drilling activity for this engine, the mass emissions associated with this model year are first divided by the population value to obtain the mass emissions rate per year for one engine (e.g., 0.00434 tons per year CO per 0.0279 engines = 0.156 tons per year per unit). Finally, this value is multiplied by the average number of engines of this type for the given well type (e.g., 1.7 mechanical draw works engines per shallow well drill rig) to obtain the emission factor expressed as mass emissions for each engine category/well type combination per 1,000 feet of drilling activity.

Total hydrocarbon (THC) exhaust emissions outputs from the NONROAD model required an additional calculation step, and were converted to VOC and TOG using ratios of 1.053 and 1.070, respectively (U.S. EPA, 2005a). Crankcase THC emissions were assumed to be equivalent to both VOC and TOG (U.S. EPA, 2005b). For diesel nonroad engines, PM_{10} is equivalent to PM, while the $PM_{2.5}$ fraction of PM_{10} is estimated to be 0.97 (U.S. EPA, 2005a).

The above process was followed to develop emission factors for each of the three model rig types, for both uncontrolled and controlled scenarios. The uncontrolled scenario was developed by running the NONROAD model for the 1990 calendar year. Diesel engines

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[5] The NONROAD model itself employs emission factors expressed in grams per brake-hp-hr of engine use. The ERG methodology avoids use of g/bhp-hr factors; factors expressed in terms of mass emissions per 1,000 feet drilled can be combined directly with the available activity data for each county (expressed as total depth drilled per year).

[6] This methodology relies on a single model year to represent average engine age, rather than a distribution across model years (which is expected in actual use). This approach will likely bias the emission estimates high to some degree. This simplification was made for a number of reasons. First, the rig survey data was not robust enough to develop new model year distributions for the different equipment/rig profiles. Nevertheless, ERG could have modified the default scrappage curve and growth factors used by the NONROAD model to develop in-use model year distributions, with average ages set to the survey values. However, the required calculation is under-specified since both the engine population growth rates and the scrappage rates for the different equipment/rig type populations is unknown. In addition, the exceedingly rapid expansion of the industry in the past few years has likely skewed the in-use age distribution in ways not modeled well by the NONROAD model's logit curve. For example, a highly accelerated turnover rate for older, less reliable engines was anticipated for the deep well category – indirectly confirmed by the new survey data. For these reasons ERG selected the simplified approach to engine age characterization, providing conservative (i.e., "high end") emission estimates.

operating in 1990 were not subject to emission controls and therefore represent uncontrolled conditions. The controlled scenario (used for calendar years 2012 – 2040) reflects the emission controls in place for any given year, and are accounted for in the NONROAD model emission factors output for each analysis year. Depending upon the analysis year in question, one or more of the following emission controls are reflected in the controlled scenario:

- Federal Emission Standards for Heavy-Duty and Non-Road Engines – "1998 HD and Non-Road Rule";
- Tier 1, Tier 2, and Tier 3 Emission Standards: Control of Emissions of Air Pollution from Non-Road Diesel Engines – "Tier 1, 2 and 3 Rule"; and
- Clean Air Non-Road Diesel – Tier 4 Final Rule – "Tier 4 Rule", including ultra-low sulfur requirements for Non-Road diesel fuel.

None of these rules are accounted for in the uncontrolled scenario.

6.3 Well Type Emission Factors

Once the final emission factors by rig type for each well category were developed, the distribution of rig types for each well category (derived as discussed in Section 4.2) were used to develop a composite set of emission factors for each well type. The composite well type emissions profile was developed by aggregating the mechanical and electrical rig types together based upon the percentage of wells associated with each rig type. For example, for the horizontal well type, approximately 86% of the wells were drilled by electrical rigs, so the resultant emission factors are weighted 86% by the NONROAD electrical rig emission factors, and 14% by the mechanical rig (for wells > 7,000 feet) emission factors. For wells > 7,000 feet, 20% of the wells are estimated to be drilled using electric rigs, and a similar weighting scheme was used to develop the composite emission factors

For wells < 7,000 feet, less than 5% are estimated to be drilled using electric rigs. For this study, it was assumed that all wells < 7,000 feet were drilled by mechanical rigs. In addition to no data being obtained through the survey showing the use of electric rigs on these shallow wells, this assumption is also supported by the data obtained during the 2009 study, which also showed no electric rig use on shallow wells

Table 6-5, Table 6-6 and Table 6-7 contain the resultant criteria pollutant emission factors developed for each well type category for the emission inventory target years. Note that emission factors for uncontrolled emission inventory estimates were set equal to the 1990 factors below, as these pre-date the introduction of diesel engine controls.

Table 6-5. Emission Factors for Vertical Wells <= 7,000 feet (tons/1,000 feet)

Year	NO_X	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
1990	0.29092	0.03518	0.04687	0.18318	0.03683	0.03573
2012	0.23420	0.00006	0.02304	0.09997	0.01500	0.01455
2013	0.23129	0.00006	0.02308	0.09997	0.01498	0.01453
2014	0.23129	0.00007	0.02308	0.09997	0.01498	0.01453
2015	0.20694	0.00007	0.02308	0.09998	0.01463	0.01419
2016	0.21089	0.00007	0.01727	0.07568	0.00810	0.00785
2017	0.20527	0.00007	0.01730	0.07568	0.00804	0.00779
2018	0.20527	0.00007	0.01730	0.07568	0.00804	0.00779
2019	0.18388	0.00007	0.01263	0.06297	0.00619	0.00601
2020	0.16511	0.00006	0.01186	0.04264	0.00463	0.00449
2021	0.16511	0.00006	0.01186	0.04264	0.00463	0.00449
2022	0.16511	0.00006	0.01186	0.04264	0.00463	0.00449
2023	0.14634	0.00006	0.01186	0.04264	0.00463	0.00449
2024	0.10506	0.00006	0.00749	0.01855	0.00304	0.00295
2025	0.10506	0.00006	0.00749	0.01855	0.00304	0.00295
2026	0.10353	0.00006	0.00746	0.01812	0.00304	0.00295
2027	0.10353	0.00006	0.00746	0.01812	0.00304	0.00295
2028	0.10353	0.00006	0.00746	0.01812	0.00304	0.00295
2029	0.08853	0.00006	0.00746	0.01813	0.00286	0.00277
2030	0.08534	0.00006	0.00743	0.01771	0.00284	0.00276
2031	0.07216	0.00006	0.00743	0.01771	0.00244	0.00236
2032	0.07216	0.00006	0.00743	0.01771	0.00244	0.00236
2033	0.07051	0.00006	0.00743	0.01771	0.00239	0.00231
2034	0.04645	0.00006	0.00571	0.01082	0.00132	0.00128
2035	0.04645	0.00006	0.00571	0.01082	0.00132	0.00128
2036	0.04645	0.00006	0.00571	0.01082	0.00132	0.00128
2037	0.03320	0.00006	0.00556	0.01083	0.00125	0.00121
2038	0.03320	0.00006	0.00556	0.01083	0.00125	0.00121
2039	0.02169	0.00005	0.00498	0.00367	0.00023	0.00022
2040	0.02169	0.00005	0.00498	0.00367	0.00023	0.00022

Table 6-6. Emission Factors for Vertical Wells > 7,000 feet (tons/1,000 feet)

Year	NO_X	SO_2	VOC	CO	PM_{10}	PM2.5
1990	0.70222	0.08497	0.11307	0.44028	0.08786	0.08523
2012	0.43234	0.00015	0.01985	0.08020	0.01024	0.00993
2013	0.43234	0.00015	0.01985	0.08020	0.01024	0.00993
2014	0.29658	0.00016	0.01923	0.08026	0.00875	0.00849
2015	0.28910	0.00016	0.01917	0.07926	0.00871	0.00845
2016	0.27681	0.00016	0.01882	0.07926	0.00869	0.00843

Table 6-6. Emission Factors for Vertical Wells > 7,000 feet (tons/1,000 feet)

Year	NO_X	SO_2	VOC	CO	PM_{10}	PM2.5
2017	0.26468	0.00016	0.01806	0.07926	0.00879	0.00853
2018	0.26468	0.00016	0.01518	0.06685	0.00803	0.00779
2019	0.16976	0.00012	0.01669	0.02814	0.00266	0.00258
2020	0.16976	0.00012	0.01669	0.02814	0.00266	0.00258
2021	0.16976	0.00012	0.01669	0.02814	0.00266	0.00258
2022	0.12541	0.00012	0.01669	0.02814	0.00266	0.00258
2023	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2024	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2025	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2026	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2027	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2028	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2029	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2030	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2031	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2032	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2033	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2034	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2035	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2036	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2037	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2038	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2039	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138
2040	0.12541	0.00012	0.01202	0.00798	0.00142	0.00138

Table 6-7. Emission Factors for Directional/Horizontal Wells (tons/1,000 feet)

Year	NO_X	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
1990	0.71765	0.08686	0.11554	0.44947	0.08952	0.08684
2012	0.38008	0.00015	0.01702	0.07053	0.01084	0.01051
2013	0.38008	0.00015	0.01702	0.07053	0.01084	0.01051
2014	0.22914	0.00013	0.02532	0.07057	0.00644	0.00625
2015	0.22787	0.00013	0.02531	0.07040	0.00643	0.00624
2016	0.22578	0.00013	0.02525	0.07040	0.00643	0.00624
2017	0.22371	0.00013	0.02512	0.07040	0.00645	0.00625
2018	0.22371	0.00013	0.01282	0.01737	0.00321	0.00311
2019	0.20755	0.00013	0.01308	0.01078	0.00229	0.00222
2020	0.20755	0.00013	0.01308	0.01078	0.00229	0.00222
2021	0.20755	0.00013	0.01308	0.01078	0.00229	0.00222
2022	0.20000	0.00013	0.01308	0.01078	0.00229	0.00222

Table 6-7. Emission Factors for Directional/Horizontal Wells (tons/1,000 feet)

Year	NO_X	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
2023	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2024	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2025	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2026	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2027	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2028	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2029	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2030	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2031	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2032	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2033	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2034	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2035	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2036	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2037	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2038	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2039	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202
2040	0.20000	0.00013	0.01228	0.00735	0.00208	0.00202

A clear pattern is apparent from the above tables. For example, in Tables 6-6 and 6-7 the emission factors decrease steadily up to 2022, after which time they are constant. This reflects the impact of the relatively low average engine age for deep vertical and directional wells – by 2022 all pre-Tier 4 engines have been replaced with Tier 4 models (fully phased in by 2014).

Table 6-7 also shows a short-lived increase in VOC emission factors from 2014 to 2017. This increase is a byproduct of the way the Tier 4 engine standards are phased in. Specifically, since the Tier 4 standards focus on NO_X and PM reductions, engine manufacturers were allowed to have a slight increase in VOC emissions during the phase in period from 2011 to 2014.[7] Starting with model year 2015, the final Tier 4 standards cut the VOC[8] limits approximately in half, reflected in the substantial decrease in the VOC factor from 2017 to 2018.

Appendix D contains the final emission factors for all pollutants for all years.

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[7] Given the very low average age of the engines used on electric rigs (2.5 years), the emission factors from 2014 through 2017 reflect engine model years between 2011 and 2014.

[8] Tier 4 standards are actually expressed in terms of NMHC rather than VOC, but the relative impact is very similar for both pollutants.

7.0 Emissions Inventory Development and Results

Historical activity data from the RRC, projected 2015 through 2040 activity data derived from DOE EIA data, and the updated emissions profiles developed for each well type category as described above were utilized to develop emissions estimates for selected target years, as described in the following sections. Note that small engines – e.g., 25 hp and less – were excluded from the survey effort due to their anticipated low levels of emissions. In addition, the survey results did not find any engines powered by gasoline or natural gas, so emission inventory estimates were limited to diesel engines.

7.1 Activity Data

7.1.1 2012, 2013, and 2014 Historical Activity

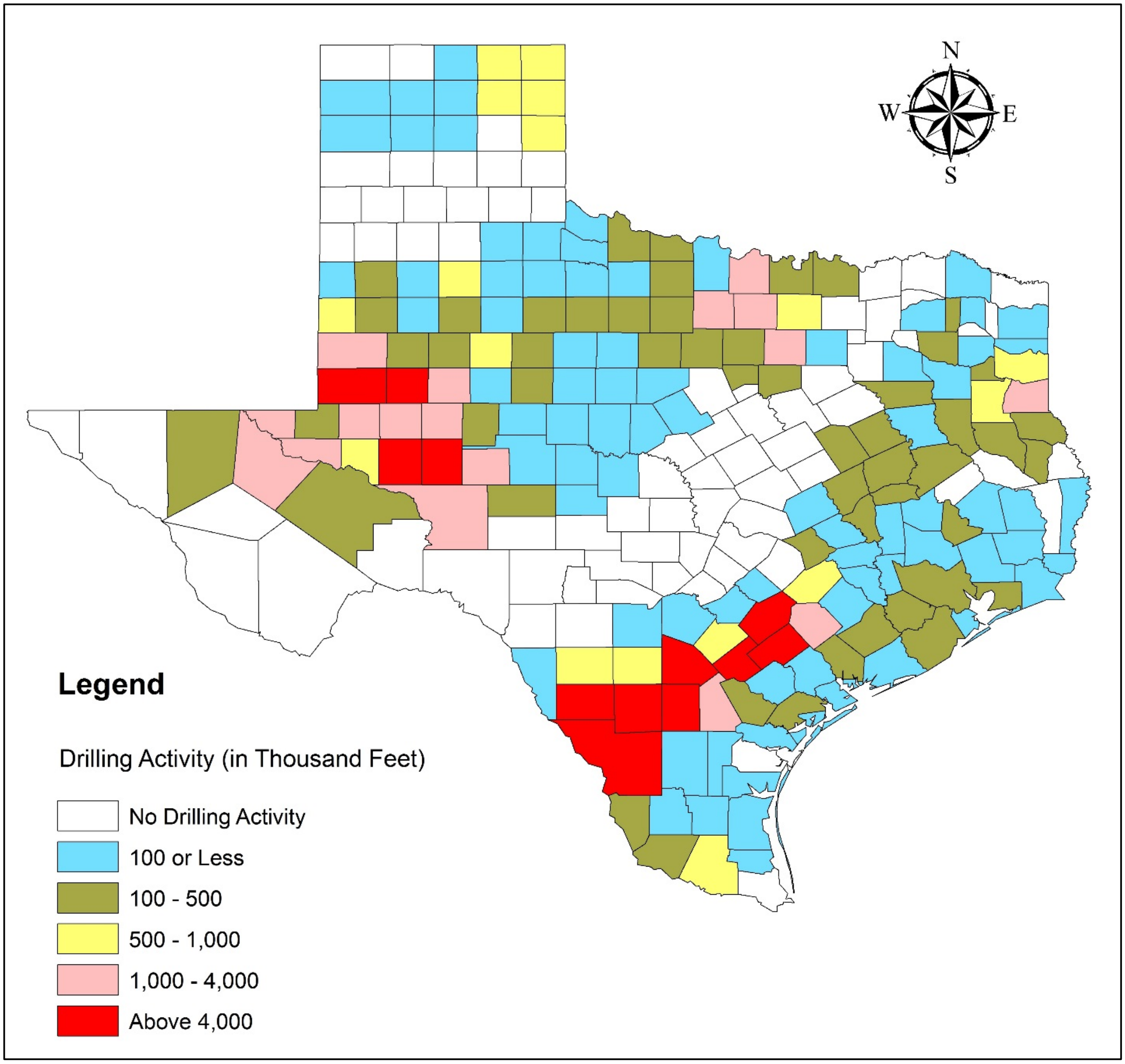
The RRC maintains oil and natural gas drilling permits for the state of Texas. In addition to descriptive information about each permit record (i.e., permit number, American Petroleum Institute (API) number, Well ID, etc.), the RRC data file contains information for when drilling began (Spud Date), when drilling was completed (Drilling Completion Date), wellbore profile type (vertical or horizontal), and permitted well depth.

Historical drilling activity data for the years 2012, 2013, and 2014 were based on the "TCEQ Air Quality Data Set" obtained by the TCEQ from the RRC through an open records request. [9] Figure 7-1 shows the level of activity in each county in Texas during 2014. The counties with the highest level of activity correspond to the liquid-rich plays being developed in the Permian Basin in west Texas and the Eagle Ford Shale in the south-central part of the state. Other areas of elevated activity in 2014 include the Barnett Shale in north Texas, and the Haynesville Shale in east Texas. According to the RRC [10], 2014 saw the highest level of drilling activity in Texas since 1984.

[9] Historical drilling activity data provided to the TCEQ by the RRC through Work Order 33408 on February 2, 2015.

[10] Annual and Monthly Drilling, Completion, and Plugging Summaries are available on-line at http://www.rrc.state.tx.us/oil-gas/research-and-statistics/well-information/monthly-drilling-completion-and-plugging-summaries/.

Figure 7-1. 2014 Texas Drilling Activity

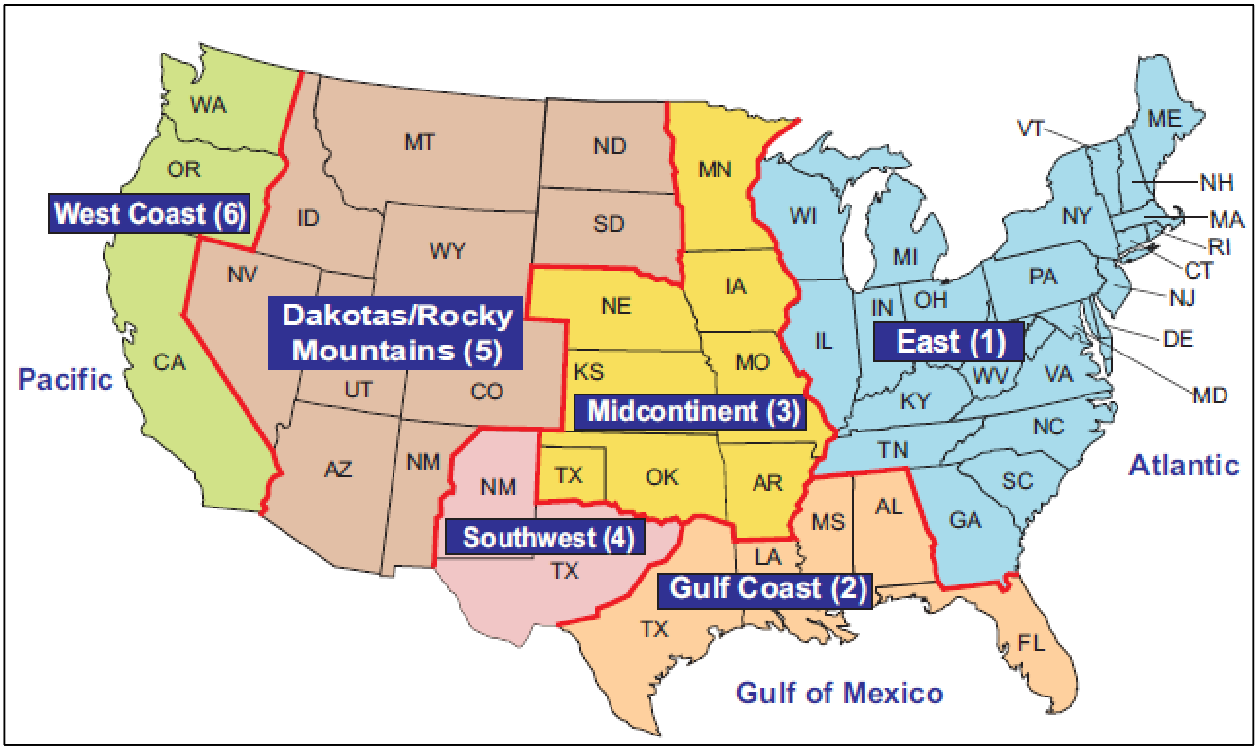


7.1.2 2015 through 2040 Projected Activity

2015 through 2040 projected drilling activity data were developed using the 2014 base year drilling activity data from the RRC and forecasting future activity based on US DOE EIA projections of oil and gas production for the Southwest and Gulf Coast regions from the *Annual Energy Outlook 2015, with projections to 2040* report. The EIA data tables present estimated crude oil and natural gas production estimates for the years 2014 through 2040. The geographic level of the projected data is by EIA Region.

Portions of Texas fall into three EIA Regions: Gulf Coast (Region 2); Southwest (Region 4); and Midcontinent (Region 3). The majority of the State is in the Gulf Coast and Southwest EIA Regions. These two regions include the Permian Basin and the Eagle Ford Shale, the primary areas of drilling activity in Texas in 2014. Only a small portion of Texas (the Texas panhandle area to the west of Oklahoma) is in the Midcontinent Region. It was assumed that the Southwest and Gulf Coast EIA Regions are equally representative of current Texas oil and gas activity, and each region was weighted equally to determine the statewide projections of future drilling activity. Figure 7-2 shows the EIA regions and their coverage in Texas.

Figure 7-2. EIA Regions



Tables 7-1 and 7-2 show projected crude oil and natural gas production for the Gulf Coast and Southwest EIA Regions, as well as the combined total for both regions, from 2015 through 2040. The total percentage change of crude oil and natural gas production for each year from 2015 through 2040 is presented relative to the base year of 2014.

This data was then used to calculate a total projected growth factor (%) for each year from 2015 through 2040 by weighing the oil and gas percentage growth figures relative to the number of oil and gas wells completed in Texas in 2014. For example, the projected growth factor for 2015 is calculated as follows:

2015 growth factor = ((% change from 2014 to 2015 in Crude Oil Production x number of oil well completions in 2014) + (% change from 2014 to 2015 in Natural Gas Production x number of gas well completions in 2014)) / (total number of oil and gas well completions in 2014)

Therefore, the projected growth factor for 2015 is:

2015 growth factor = ((10.27% x 23,521) + (-3.47% x 3,186)) / (23,521 + 3,186) = 8.63%

Table 7-3 shows the resultant total projected growth factors that were developed for each projected year as a result of this analysis. These factors were then applied to the 2014 base year well depth totals by county for each of the three well categories to determine activity data (total feet drilled) for 2015 through 2040.

As noted above, 2014 saw the highest level of drilling activity in Texas since 1984. This was due to relatively high crude oil prices from 2011 through mid-2014, with the price of crude averaging at or near $100/barrel over this time frame. By the end of 2014, crude oil commodity prices were severely depressed from these highs with crude oil reaching $50/barrel by year's end. Not surprisingly, drilling activity began to decline towards the end of the year, a trend that has carried forward into 2015.

It should be noted that the projected production data in the DOE EIA report does not reflect a reduction in activity in 2015 as the EIA projections are more reflective of a long-term outlook and show macro-trends in production (increased domestic energy production due to shale oil and gas resource). Price fluctuations may have a more prominent impact year-to-year, as reflected in the 2014 to early 2015 downward trend in drilling activity.

Projected drilling activity for the years 2015 through 2040 estimated as described above may be found in Appendix E (TCEQ 2015_2040 Projected Drilling Activity.xlsx).

Table 7-1. Projected Crude Oil Production 2015-2040

Year	Gulf Coast EIA Region (MMBBL/day)	Southwest EIA Region (MMBBL/day)	Total (MMBBL/day)	% change from 2014
2014	1.98	1.72	3.7	NA
2015	2.23	1.85	4.08	10.27
2016	2.23	1.98	4.21	13.78
2017	2.28	2.05	4.33	17.03
2018	2.26	2.13	4.39	18.65
2019	2.24	2.17	4.41	19.19
2020	2.18	2.21	4.39	18.65
2021	2.07	2.26	4.33	17.03

Table 7-1. Projected Crude Oil Production 2015-2040

Year	Gulf Coast EIA Region (MMBBL/day)	Southwest EIA Region (MMBBL/day)	Total (MMBBL/day)	% change from 2014
2022	1.99	2.29	4.28	15.68
2023	1.91	2.32	4.23	14.32
2024	1.85	2.35	4.2	13.51
2025	1.78	2.37	4.15	12.16
2026	1.68	2.37	4.05	9.46
2027	1.61	2.38	3.99	7.84
2028	1.57	2.38	3.95	6.76
2029	1.55	2.36	3.91	5.68
2030	1.51	2.33	3.84	3.78
2031	1.48	2.24	3.72	0.54
2032	1.45	2.16	3.61	-2.43
2033	1.43	2.09	3.52	-4.86
2034	1.41	2.03	3.44	-7.03
2035	1.39	1.98	3.37	-8.92
2036	1.38	1.95	3.33	-10
2037	1.37	1.92	3.29	-11.08
2038	1.37	1.9	3.27	-11.62
2039	1.37	1.89	3.26	-11.89
2040	1.37	1.88	3.25	-12.16

Table 7-2. Projected Natural Gas Production 2015-2040

Year	Gulf Coast EIA Region (trillion cubic feet)	Southwest EIA Region (trillion cubic feet)	Total (trillion cubic feet)	% change from 2014
2014	5.05	3.89	8.94	NA
2015	4.93	3.7	8.63	-3.47
2016	5.1	3.77	8.87	-0.78
2017	5.14	3.76	8.9	-0.45
2018	5.29	3.9	9.19	2.8
2019	5.56	4.03	9.59	7.27
2020	5.91	4.11	10.02	12.08
2021	6.29	4.13	10.42	16.55
2022	6.68	4.16	10.84	21.25
2023	6.98	4.21	11.19	25.17
2024	7.25	4.23	11.48	28.41
2025	7.47	4.24	11.71	30.98
2026	7.65	4.24	11.89	33
2027	7.84	4.24	12.08	35.12
2028	7.94	4.23	12.17	36.13
2029	8.05	4.19	12.24	36.91
2030	8.09	4.12	12.21	36.58

Table 7-2. Projected Natural Gas Production 2015-2040

Year	Gulf Coast EIA Region (trillion cubic feet)	Southwest EIA Region (trillion cubic feet)	Total (trillion cubic feet)	% change from 2014
2031	8.21	3.99	12.2	36.47
2032	8.34	3.87	12.21	36.58
2033	8.46	3.78	12.24	36.91
2034	8.58	3.7	12.28	37.36
2035	8.7	3.64	12.34	38.03
2036	8.85	3.6	12.45	39.26
2037	9	3.57	12.57	40.6
2038	9.19	3.55	12.74	42.51
2039	9.34	3.54	12.88	44.07
2040	9.42	3.47	12.89	44.18

Table 7-3. Projected Growth Factors 2015-2040

Year	Oil Production (% change from 2014)	Natural Gas Production (% change from 2014)	Projected Growth Factor (%)[a]
2015	10.27	-3.47	8.63
2016	13.78	-0.78	12.05
2017	17.03	-0.45	14.94
2018	18.65	2.8	16.76
2019	19.19	7.27	17.77
2020	18.65	12.08	17.87
2021	17.03	16.55	16.97
2022	15.68	21.25	16.34
2023	14.32	25.17	15.62
2024	13.51	28.41	15.29
2025	12.16	30.98	14.41
2026	9.46	33	12.27
2027	7.84	35.12	11.09
2028	6.76	36.13	10.26
2029	5.68	36.91	9.4
2030	3.78	36.58	7.7
2031	0.54	36.47	4.83
2032	-2.43	36.58	2.22
2033	-4.86	36.91	0.12
2034	-7.03	37.36	-1.73
2035	-8.92	38.03	-3.32
2036	-10	39.26	-4.12
2037	-11.08	40.6	-4.92
2038	-11.62	42.51	-5.16
2039	-11.89	44.07	-5.22
2040	-12.16	44.18	-5.44

[a] Based on 23,521 oil well and 3,186 gas well completions in 2014.

7.2 Emission Estimation Methodology

Once the total depth drilled per year was aggregated by well type category, and the emission factor profile for each well type category was developed, county level emissions for each well type category were estimated by multiplying the total depth drilled by county by the emission factors developed using the NONROAD model, as follows:

$$E_{poll/type} = (\text{Depth } (1{,}000 \text{ feet/yr})) \times (EF_{poll} \text{ (tons/1,000 feet)})$$

Where:

Epoll/type	=	Emission of pollutant for each county by well type category (tons/yr)
Depth	=	Total depth drilled in well type category by county (1,000 feet/yr)
EFpoll	=	Pollutant emission factor (tons/1,000 feet)

This process is repeated for each pollutant for each year for each well type category – for example, 2014 NO_x emissions for shallow vertical wells (< 7,000 feet).

For 2006 onward, NO_x emission estimates for the 110 counties in the eastern half of Texas subject to the Texas Low Emission Diesel (TxLED) program were adjusted downward by 6.2% to account for the effect of the rule. Table 7-4 identifies the counties where this adjustment was made.

Table 7-4. TxLED Counties

Anderson	Denton	Johnson	Robertson
Angelina	Ellis	Karnes	Rockwall
Aransas	Falls	Kaufman	Rusk
Atascosa	Fannin	Lamar	Sabine
Austin	Fayette	Lavaca	San Jacinto
Bastrop	Franklin	Lee	San Patricio
Bee	Freestone	Leon	San Augustine
Bell	Fort Bend	Liberty	Shelby
Bexar	Galveston	Limestone	Smith
Bosque	Goliad	Live Oak	Somervell
Bowie	Gonzales	Madison	Tarrant
Brazoria	Grayson	Marion	Titus
Brazos	Gregg	Matagorda	Travis
Burleson	Grimes	McLennan	Trinity
Caldwell	Guadalupe	Milam	Tyler
Calhoun	Hardin	Montgomery	Upshur

Table 7-4. TxLED Counties

Camp	Harris	Morris	Van Zandt
Cass	Harrison	Nacogdoches	Victoria
Chambers	Hays	Navarro	Walker
Cherokee	Henderson	Newton	Waller
Collin	Hill	Nueces	Washington
Colorado	Hood	Orange	Wharton
Comal	Hopkins	Panola	Williamson
Cooke	Houston	Parker	Wilson
Coryell	Hunt	Polk	Wise
Dallas	Jackson	Rains	
De Witt	Jasper	Red River	
Delta	Jefferson	Refugio	

For counties subject to TxLED requirements, NO_x emissions were estimated as follows:

ENO_x-type = (Depth (1,000 feet/yr)) x ($EFNO_x$ (tons/1,000 feet)) x (0.938)

Where:

ENO_x-type = Emission of NO_x for each county by well type category (tons/yr)

Depth = Total depth drilled in well type category by county (1,000 feet/yr)

$EFNO_x$ = NO_x emission factor (tons/1,000 feet)

(0.938) = Adjustment factor to account for 6.2% TxLED reduction

Total county level emissions were then determined by summing emissions for each of the three model rig categories for a particular county for a given year.

7.2.1 Example Emission Calculations

Using the data above, CO emissions in 2014 for Anderson County from vertical wells > 7,000 feet are estimated as follows:

ECO = (Depth (1,000 feet/yr)) x (EFpoll (tons/1,000 feet)), or
ECO = (33.72 (1,000 feet/yr)) x (0.080 (tons/1,000 feet))
ECO = 2.7 (tons/yr)

As Anderson County is subject to the TxLED requirements, NO_x emissions in 2014 for Anderson County from vertical wells > 7,000 feet are estimated as follows:

E_{NO_x} = (Depth (1,000 feet/yr)) x (EFpoll (tons/1,000 feet)) x (0.938), or
E_{NO_x} = (33.72 (1,000 feet/yr)) x (0.297 (tons/1,000 feet)) x (0.938)
E_{NO_x} = 9.4 (tons/yr)

7.3 Results

7.3.1 Emission Summary

Tables 7-5 through 7-8, as well as Figures 7-3 through 7-7 summarize the statewide annual and ozone-season daily criteria emissions totals for diesel engine drill rigs, for both controlled and uncontrolled scenarios. Note that the impact of the state TxLED rule (discussed above) is also included in all controlled scenario estimates.

HAP emissions estimates and by-county breakouts were provided in the electronic XML files submitted to the TCEQ. Appendix A also provides the statewide emission estimates for HAPs.

Table 7-5. Statewide Annual Emissions Totals (Tons/Year), Controlled Scenario

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
2012	41,724	16	2,068	8,566	1,259	1,221
2013	38,167	15	1,890	7,826	1,149	1,115
2014	36,488	20	3,249	11,278	1,213	1,176
2015	38,629	22	3,524	12,173	1,308	1,269
2016	38,934	22	3,501	12,110	1,228	1,191
2017	38,842	23	3,528	12,423	1,267	1,229
2018	39,456	23	2,419	7,598	980	951
2019	31,423	20	2,479	4,098	492	477
2020	31,090	20	2,466	3,709	462	448
2021	30,855	20	2,448	3,681	459	445
2022	27,011	20	2,434	3,661	456	443
2023	26,492	20	2,026	1,940	349	339
2024	25,645	19	1,938	1,481	318	309
2025	25,448	19	1,923	1,469	316	306
2026	24,944	19	1,886	1,434	310	301
2027	24,683	19	1,867	1,419	307	298
2028	24,499	19	1,853	1,408	305	295
2029	24,042	18	1,838	1,398	299	290
2030	23,611	18	1,809	1,368	294	285
2031	22,758	18	1,761	1,332	279	271
2032	22,192	17	1,717	1,299	272	264
2033	21,709	17	1,682	1,272	266	258
2034	20,924	17	1,623	1,138	244	237
2035	20,587	16	1,597	1,119	240	233
2036	20,415	16	1,583	1,110	238	231
2037	20,042	16	1,568	1,101	235	228
2038	19,989	16	1,564	1,098	234	227

Table 7-5. Statewide Annual Emissions Totals (Tons/Year), Controlled Scenario

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
2039	19,802	16	1,554	987	218	212
2040	19,755	16	1,550	984	218	211

Figure 7-3. Statewide Drilling Rig Emissions – Controlled (NO_x and CO Tons/Year)

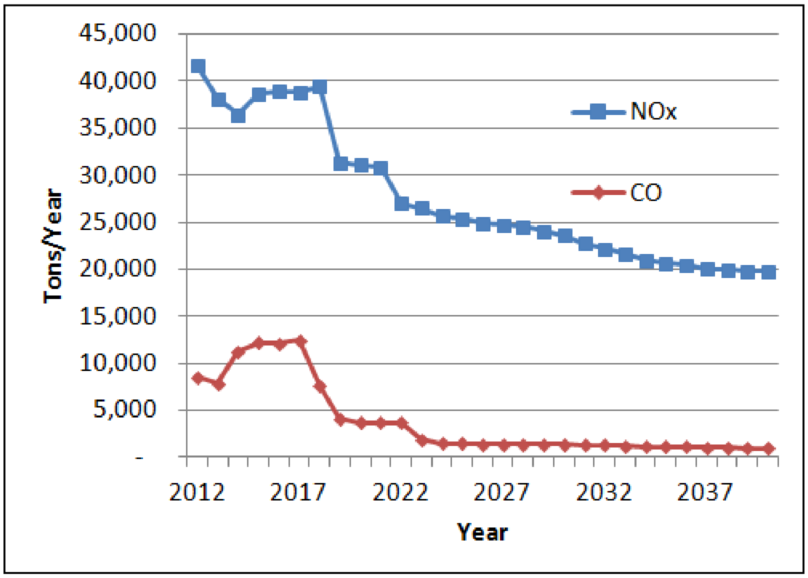
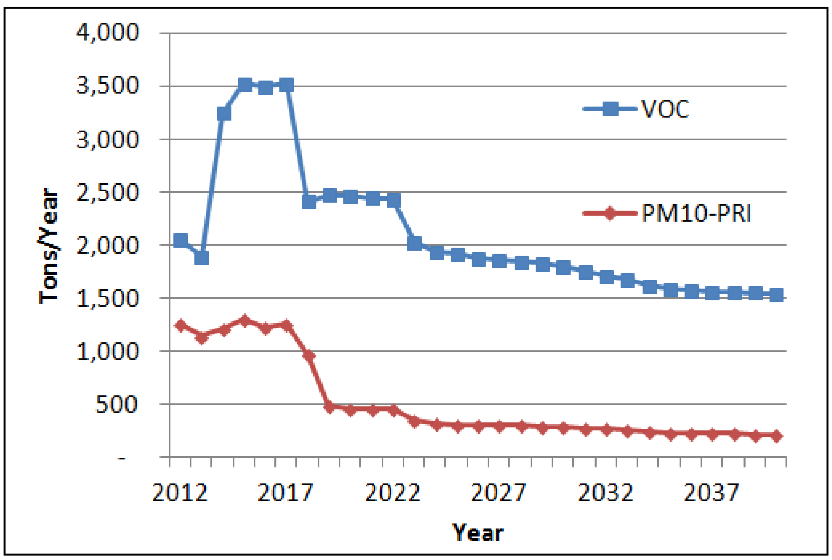


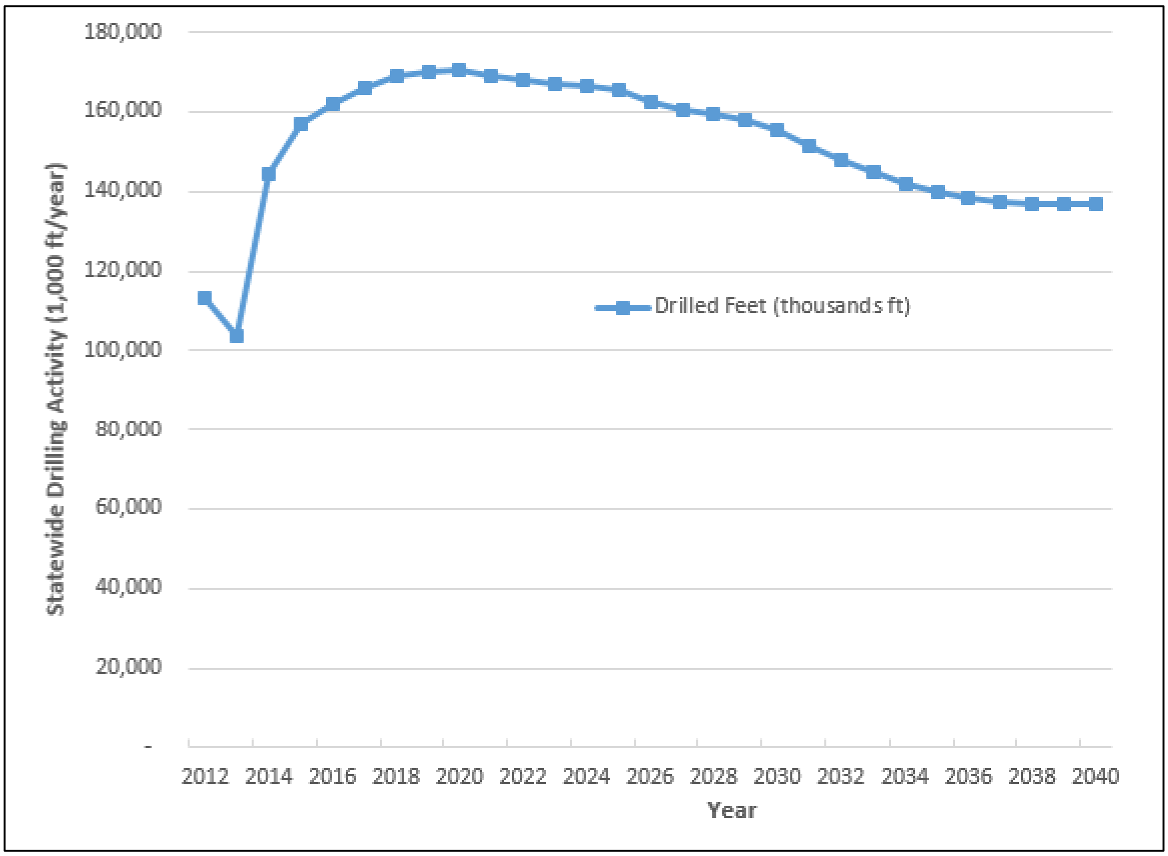
Figure 7-4. Statewide Drilling Rig Emissions – Controlled (VOC and PM_{10} Tons/Year)



Figures 7-3 and 7-4 show a general increase in most pollutants through 2017, after which time emissions drop off dramatically due to decreased drilling activity as well as continued turnover of the drilling rig fleet to newer engines subject to Tier 2, 3, and 4 non-road diesel engine standards. Figure 7-5 presents the corresponding statewide drilling activity for comparison.

The pronounced drop in emissions between 2017 and 2018 reflects the complete replacement of older electric rig engines with Tier 4 engines. A less dramatic drop-off occurs again with a similar replacement of pre-Tier 4 engines with Tier 4 units for deep vertical rigs. Emission reductions resulting from Tier 4 introduction are significant for all four pollutants shown above, although a temporary increase in VOC is seen through 2017 (discussed in more detail in Section 6.3).

Figure 7-5. Statewide Annual Drilling Rig Activity (1,000 feet)



Ozone season day (OSD) emissions were calculated by dividing annual emissions estimates by 365. These values are presented in the tables below. Note that trend charts are not presented for OSD totals, since the relative emissions over time are the same as the annual emissions cases above.

Table 7-6. Statewide OSD Emissions Totals (Tons/Day), Controlled Scenario

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
2012	114.31	0.044	5.67	23.47	3.45	3.34
2013	104.57	0.040	5.18	21.44	3.15	3.05
2014	99.97	0.054	8.90	30.90	3.32	3.22
2015	105.83	0.059	9.66	33.35	3.58	3.48
2016	106.67	0.061	9.59	33.18	3.36	3.26
2017	106.42	0.062	9.67	34.04	3.47	3.37
2018	108.10	0.064	6.63	20.82	2.69	2.60
2019	86.09	0.055	6.79	11.23	1.35	1.31
2020	85.18	0.055	6.76	10.16	1.27	1.23
2021	84.53	0.054	6.71	10.09	1.26	1.22
2022	74.00	0.054	6.67	10.03	1.25	1.21
2023	72.58	0.054	5.55	5.32	0.96	0.93
2024	70.26	0.053	5.31	4.06	0.87	0.85
2025	69.72	0.053	5.27	4.03	0.87	0.84
2026	68.34	0.052	5.17	3.93	0.85	0.82
2027	67.63	0.051	5.11	3.89	0.84	0.82
2028	67.12	0.051	5.08	3.86	0.83	0.81
2029	65.87	0.051	5.04	3.83	0.82	0.79
2030	64.69	0.050	4.96	3.75	0.81	0.78
2031	62.35	0.049	4.82	3.65	0.76	0.74
2032	60.80	0.047	4.70	3.56	0.75	0.72
2033	59.48	0.046	4.61	3.48	0.73	0.71
2034	57.33	0.045	4.45	3.12	0.67	0.65
2035	56.40	0.045	4.37	3.07	0.66	0.64
2036	55.93	0.044	4.34	3.04	0.65	0.63
2037	54.91	0.044	4.30	3.02	0.64	0.62
2038	54.77	0.044	4.28	3.01	0.64	0.62
2039	54.25	0.043	4.26	2.70	0.60	0.58
2040	54.12	0.043	4.25	2.70	0.60	0.58

Table 7-7. Statewide Annual Emissions Totals (Tons/Year), Uncontrolled Scenario

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
2012	76,260	9,229	12,279	47,785	9,526	9,240
2013	69,773	8,444	11,234	43,720	8,715	8,454
2014	95,816	11,595	15,428	60,056	11,978	11,618
2015	104,086	12,596	16,760	65,239	13,011	12,621
2016	107,358	12,992	17,286	67,290	13,420	13,018
2017	110,133	13,328	17,733	69,029	13,767	13,354
2018	111,872	13,538	18,013	70,120	13,985	13,565
2019	112,840	13,655	18,169	70,726	14,106	13,682
2020	112,934	13,667	18,184	70,785	14,117	13,694

Table 7-7. Statewide Annual Emissions Totals (Tons/Year), Uncontrolled Scenario

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
2021	112,077	13,563	18,046	70,248	14,010	13,590
2022	111,473	13,490	17,949	69,869	13,935	13,517
2023	110,780	13,406	17,837	69,435	13,848	13,433
2024	110,467	13,368	17,787	69,239	13,809	13,395
2025	109,621	13,266	17,651	68,708	13,703	13,292
2026	107,570	13,018	17,320	67,423	13,447	13,043
2027	106,445	12,881	17,139	66,718	13,306	12,907
2028	105,647	12,785	17,011	66,218	13,207	12,810
2029	104,825	12,685	16,878	65,702	13,104	12,711
2030	103,190	12,488	16,615	64,677	12,899	12,512
2031	100,440	12,155	16,172	62,954	12,556	12,179
2032	97,944	11,853	15,771	61,390	12,244	11,876
2033	95,930	11,609	15,446	60,127	11,992	11,632
2034	94,157	11,394	15,161	59,016	11,770	11,417
2035	92,637	11,210	14,916	58,063	11,580	11,233
2036	91,865	11,117	14,792	57,579	11,484	11,139
2037	91,106	11,025	14,670	57,104	11,389	11,047
2038	90,868	10,996	14,631	56,954	11,359	11,018
2039	90,818	10,990	14,623	56,923	11,353	11,012
2040	90,603	10,964	14,589	56,788	11,326	10,986

Figure 7-6. Statewide Drilling Rig Emissions – Uncontrolled (NO_x and CO Tons/Year)

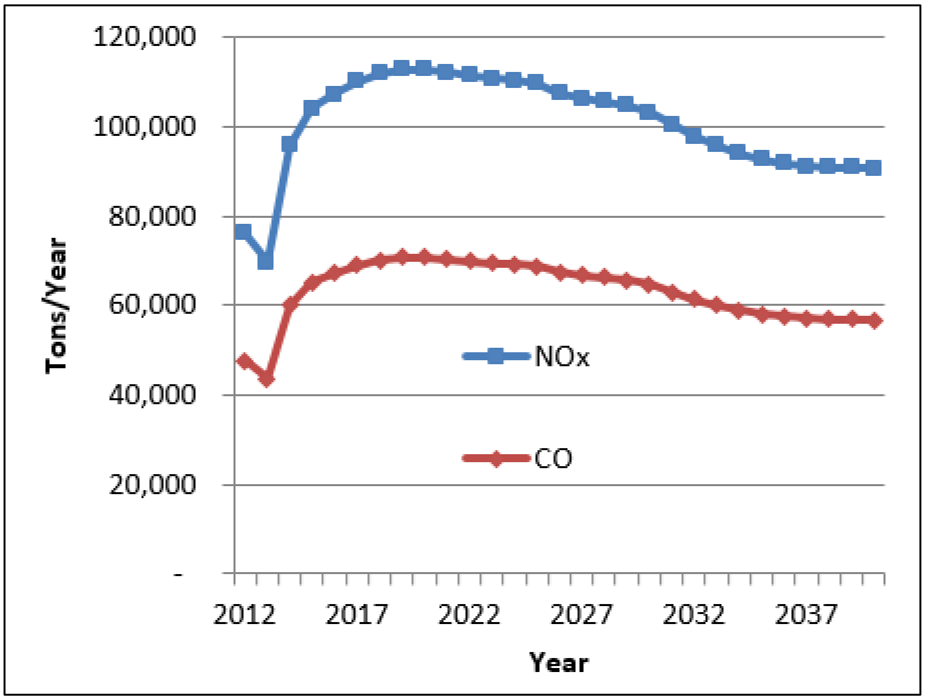
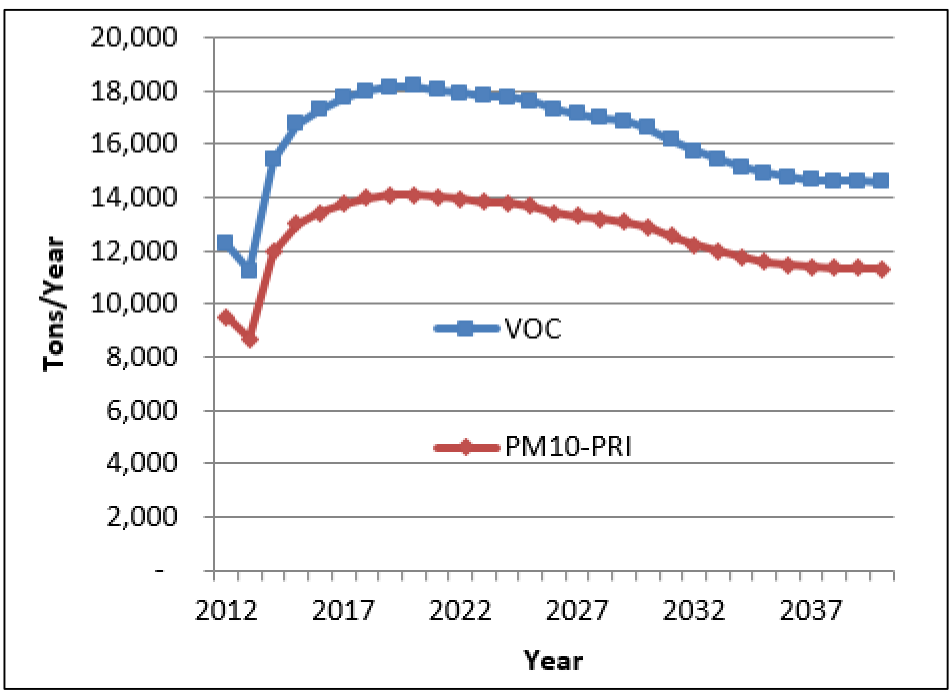


Figure 7-7. Statewide Drilling Rig Emissions – Uncontrolled (VOC and PM_{10} Tons/Year)



The emissions trends presented in Figures 7-6 and 7-7 above clearly show how emissions for all pollutants would be substantially higher without the benefit of the engine and fuel controls implemented since 1990. To illustrate this point trend graphs were also generated to compare the difference between the controlled and uncontrolled emissions scenarios directly (see Figures 7-8 through 7-11).

Figure 7-8. Controlled and Uncontrolled Emissions Projections (NO_x Tons/Year)

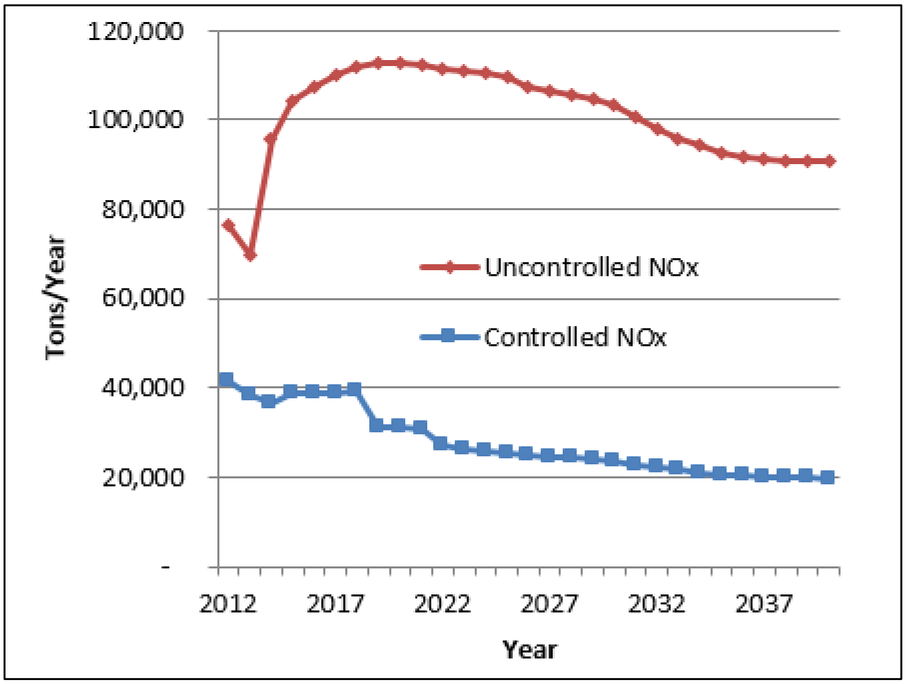


Figure 7-9. Controlled and Uncontrolled Emissions Projections (CO Tons/Year)

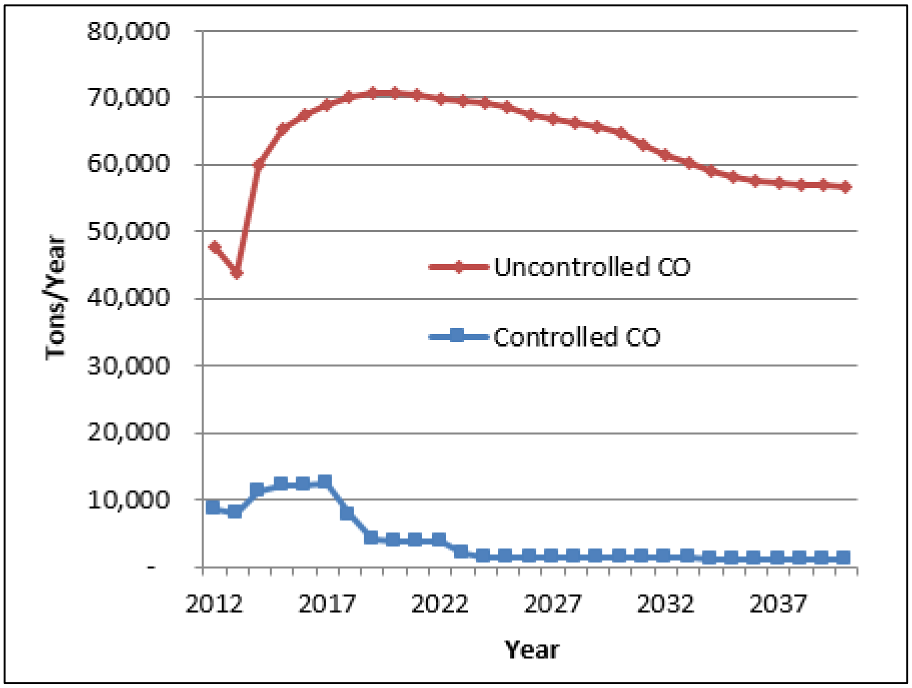


Figure 7-10. Controlled and Uncontrolled Emissions Projections (VOC Tons/Year)

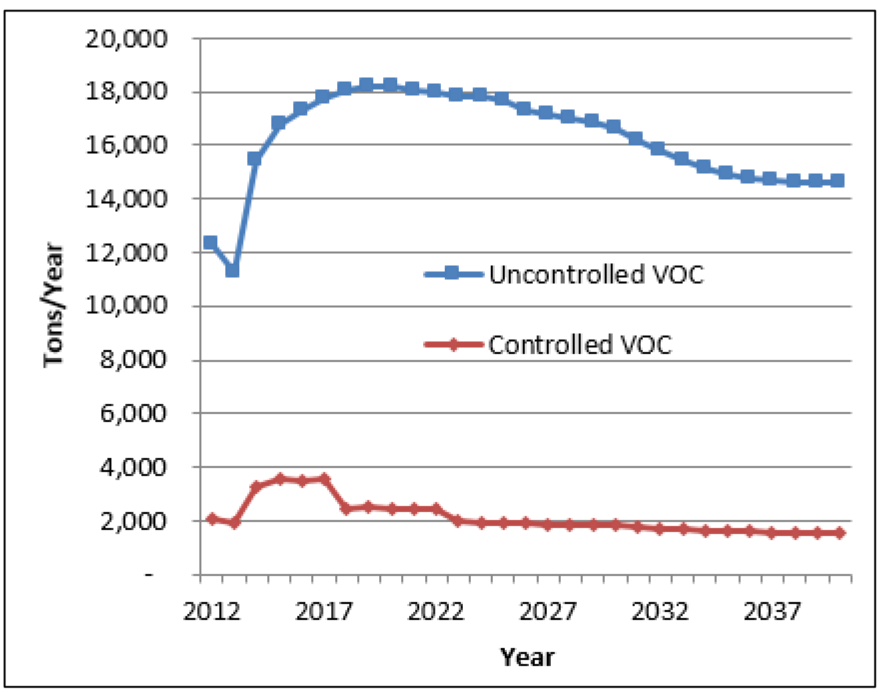
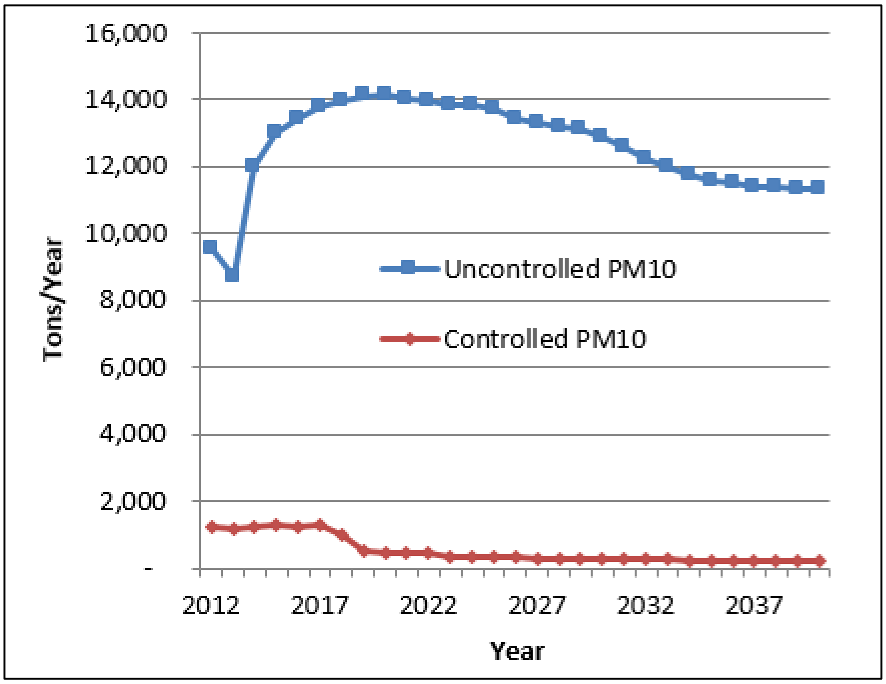


Figure 7-11. Controlled and Uncontrolled Emissions Projections (PM_{10} Tons/Year)



In addition, since the emission factors are held constant for uncontrolled estimates, the year-to-year changes shown above for the uncontrolled scenarios are exclusively due to changes in historical and projected drilling activity (see Figure 7-5).

Table 7-8. Statewide OSD Emissions Totals (Tons/Day), Uncontrolled Scenario

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
2012	208.93	25.28	33.64	130.92	26.10	25.31
2013	191.16	23.13	30.78	119.78	23.88	23.16
2014	262.51	31.77	42.27	164.54	32.82	31.83
2015	285.17	34.51	45.92	178.74	35.65	34.58
2016	294.13	35.59	47.36	184.36	36.77	35.67
2017	301.73	36.51	48.58	189.12	37.72	36.59
2018	306.50	37.09	49.35	192.11	38.31	37.16
2019	309.15	37.41	49.78	193.77	38.65	37.49
2020	309.41	37.44	49.82	193.93	38.68	37.52
2021	307.06	37.16	49.44	192.46	38.38	37.23
2022	305.41	36.96	49.18	191.42	38.18	37.03
2023	303.51	36.73	48.87	190.23	37.94	36.80
2024	302.65	36.63	48.73	189.69	37.83	36.70
2025	300.33	36.34	48.36	188.24	37.54	36.42
2026	294.71	35.66	47.45	184.72	36.84	35.74

Table 7-8. Statewide OSD Emissions Totals (Tons/Day), Uncontrolled Scenario

Year	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$
2027	291.63	35.29	46.96	182.79	36.46	35.36
2028	289.45	35.03	46.61	181.42	36.18	35.10
2029	287.19	34.75	46.24	180.01	35.90	34.82
2030	282.71	34.21	45.52	177.20	35.34	34.28
2031	275.18	33.30	44.31	172.48	34.40	33.37
2032	268.34	32.47	43.21	168.19	33.54	32.54
2033	262.82	31.81	42.32	164.73	32.85	31.87
2034	257.96	31.22	41.54	161.69	32.25	31.28
2035	253.80	30.71	40.87	159.08	31.73	30.77
2036	251.69	30.46	40.53	157.75	31.46	30.52
2037	249.61	30.21	40.19	156.45	31.20	30.27
2038	248.95	30.13	40.09	156.04	31.12	30.19
2039	248.82	30.11	40.06	155.95	31.10	30.17
2040	248.23	30.04	39.97	155.58	31.03	30.10

Annual county-level NO_x emissions were also investigated for the controlled scenario for the 2014 base year, in order to help identify the areas of the state with the greatest level of drilling rig emissions. Table 7-9 presents these emissions, with counties ranked from highest to lowest. Of the 180 counties with non-zero emissions in 2014, only a small fraction were responsible for a preponderance of total statewide emissions. For example, the top 10 counties were responsible for nearly 50 percent of total NO_x emissions. In addition, the top six counties (and seven of the top ten) are located in South-Central Texas (Eagle Ford Shale), with the others being Upton, Andrews, and Martin counties in West Texas (Permian Basin).

Table 7-9. County NO_x Emissions Estimates, 2014 Controlled Scenario

County	Tons/Year	Cumulative %
Karnes	2,679.01	7%
Dimmit	2,316.37	14%
La Salle	2,311.68	20%
De Witt	2,128.48	26%
Webb	1,927.57	31%
McMullen	1,814.81	36%
Upton	1,282.37	40%
Andrews	1,206.71	43%
Martin	1,170.47	46%
Atascosa	1,082.97	49%

Table 7-9. County NO_x Emissions Estimates, 2014 Controlled Scenario

County	Tons/Year	Cumulative %
Reagan	1,058.20	52%
Gonzales	1,020.66	55%
Midland	999.00	58%
Irion	821.60	60%
Live Oak	816.79	62%
Glasscock	801.74	64%
Ector	730.24	66%
Crockett	667.06	68%
Panola	587.96	70%
Howard	579.15	71%
Reeves	504.90	73%
Tarrant	485.92	74%
Gaines	424.82	75%
Montague	405.06	76%
Ward	391.82	77%
Wise	386.35	78%
Lavaca	310.63	79%
Loving	287.51	80%
Jack	270.03	81%
Ochiltree	246.95	81%
Harrison	239.67	82%
Denton	227.47	83%
Crane	217.28	83%
Roberts	189.92	84%
Wheeler	185.23	84%
Yoakum	184.17	85%
Zavala	169.47	85%
Frio	167.06	86%
Hidalgo	160.93	86%
Crosby	157.40	87%
Hemphill	154.73	87%
Lipscomb	154.34	87%
Rusk	148.59	88%
Scurry	142.35	88%
Dawson	139.23	89%
Wilson	137.87	89%
Freestone	132.39	89%
Fayette	123.94	90%

Table 7-9. County NO_x Emissions Estimates, 2014 Controlled Scenario

County	Tons/Year	Cumulative %
Starr	111.40	90%
Hockley	96.23	90%
Pecos	94.52	91%
Wichita	94.42	91%
Grayson	89.90	91%
Leon	83.58	91%
Cherokee	83.26	92%
San Augustine	80.68	92%
Culberson	79.88	92%
Stephens	76.39	92%
Wood	76.24	92%
Borden	74.06	93%
Madison	71.47	93%
Brazos	68.39	93%
Throckmorton	68.05	93%
Palo Pinto	64.91	93%
Sterling	64.57	94%
Shelby	62.07	94%
Refugio	61.40	94%
Terry	60.69	94%
Fort Bend	58.40	94%
Parker	56.95	94%
Nolan	56.21	95%
Chambers	53.70	95%
San Jacinto	52.88	95%
Stonewall	52.70	95%
Robertson	52.50	95%
Fisher	50.59	95%
Limestone	50.48	95%
Winkler	50.12	95%
Gregg	49.46	96%
Bee	46.87	96%
Johnson	45.99	96%
Young	45.00	96%
Garza	44.47	96%
Schleicher	42.99	96%
Nacogdoches	42.92	96%
Zapata	42.34	96%

Table 7-9. County NO_x Emissions Estimates, 2014 Controlled Scenario

County	Tons/Year	Cumulative %
Wharton	40.91	97%
Wilbarger	40.16	97%
Houston	39.40	97%
Archer	39.31	97%
Cooke	38.15	97%
Hood	37.13	97%
Haskell	33.88	97%
Brazoria	31.24	97%
Henderson	29.02	97%
Jackson	28.78	97%
Franklin	28.43	98%
Harris	28.09	98%
Brooks	27.58	98%
Lee	24.46	98%
Kleberg	22.64	98%
Dallas	22.51	98%
Mitchell	22.16	98%
Lubbock	22.07	98%
Newton	21.99	98%
Hardeman	21.90	98%
Kent	21.86	98%
Willacy	21.52	98%
Carson	20.32	98%
King	20.10	98%
Titus	19.29	98%
Burleson	18.98	98%
Kenedy	18.59	99%
Taylor	17.54	99%
Jones	17.46	99%
Walker	17.45	99%
Oldham	17.09	99%
San Patricio	16.80	99%
Duval	16.79	99%
Galveston	16.22	99%
Victoria	15.85	99%
Jim Hogg	14.65	99%
Smith	14.58	99%
Upshur	14.19	99%

Table 7-9. County NO_x Emissions Estimates, 2014 Controlled Scenario

County	Tons/Year	Cumulative %
Matagorda	14.01	99%
Baylor	13.88	99%
Orange	13.68	99%
Grimes	13.54	99%
Anderson	12.94	99%
Aransas	12.93	99%
Hansford	12.85	99%
Milam	12.72	99%
Marion	12.38	99%
Montgomery	12.14	99%
Shackelford	11.94	99%
Tom Green	11.62	99%
Runnels	11.16	99%
Maverick	11.02	99%
Jefferson	10.54	100%
Coke	10.39	100%
Liberty	9.55	100%
Lynn	8.98	100%
Tyler	8.77	100%
Hopkins	8.68	100%
Clay	8.67	100%
Caldwell	8.32	100%
Polk	7.10	100%
Cottle	7.02	100%
Coleman	7.01	100%
Cochran	6.92	100%
Hardin	6.15	100%
Dickens	6.02	100%
Hartley	5.89	100%
Austin	5.16	100%
Colorado	4.44	100%
Waller	4.23	100%
Cass	4.19	100%
Jim Wells	3.90	100%
Van Zandt	3.69	100%
Knox	3.62	100%
Concho	3.59	100%
Brown	3.45	100%

Table 7-9. County NO_x Emissions Estimates, 2014 Controlled Scenario

County	Tons/Year	Cumulative %
Medina	3.38	100%
Calhoun	2.98	100%
Goliad	2.97	100%
Comanche	2.82	100%
Hutchinson	2.73	100%
Guadalupe	2.61	100%
Callahan	2.59	100%
Bexar	2.04	100%
Menard	1.68	100%
Foard	1.43	100%
Red River	1.23	100%
Motley	1.19	100%
Eastland	1.03	100%
Potter	0.55	100%
Moore	0.55	100%
Washington	0.32	100%
McCulloch	0.25	100%
Edwards	0.06	100%

While there is some relative variation in historical estimates, most county trends follow the general pattern seen in the statewide totals (see Figure 7-3). Figures 7-12, 7-13, and 7-14 display the county-level distribution of annual NO_x, VOC, and $PM_{2.5}$ emissions for the 2014 base year.

Figure 7-12. 2014 Annual NO_x Emissions by County (Tons/Year)

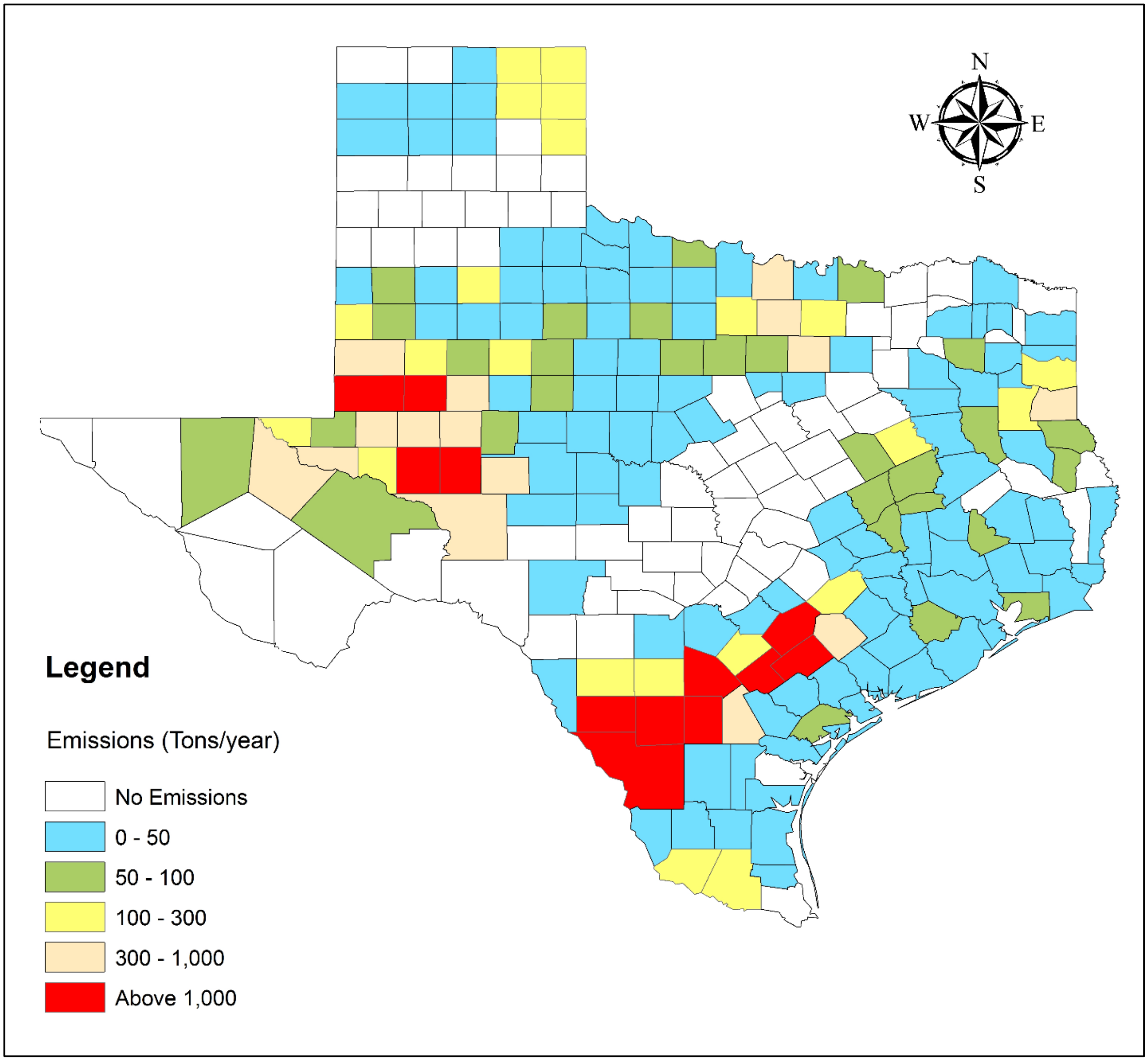


Figure 7-13. 2014 Annual VOC Emissions by County (Tons/Year)

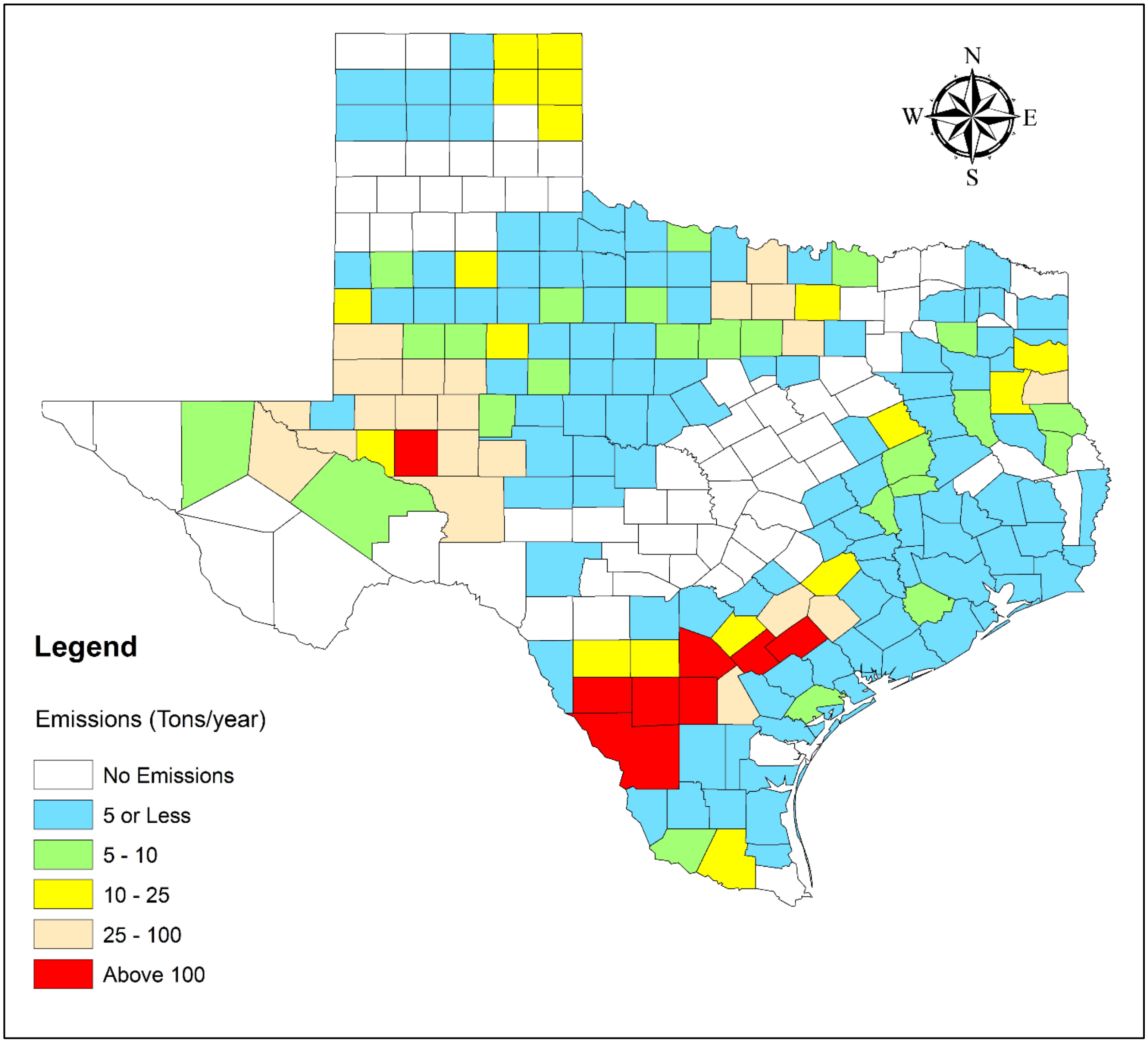
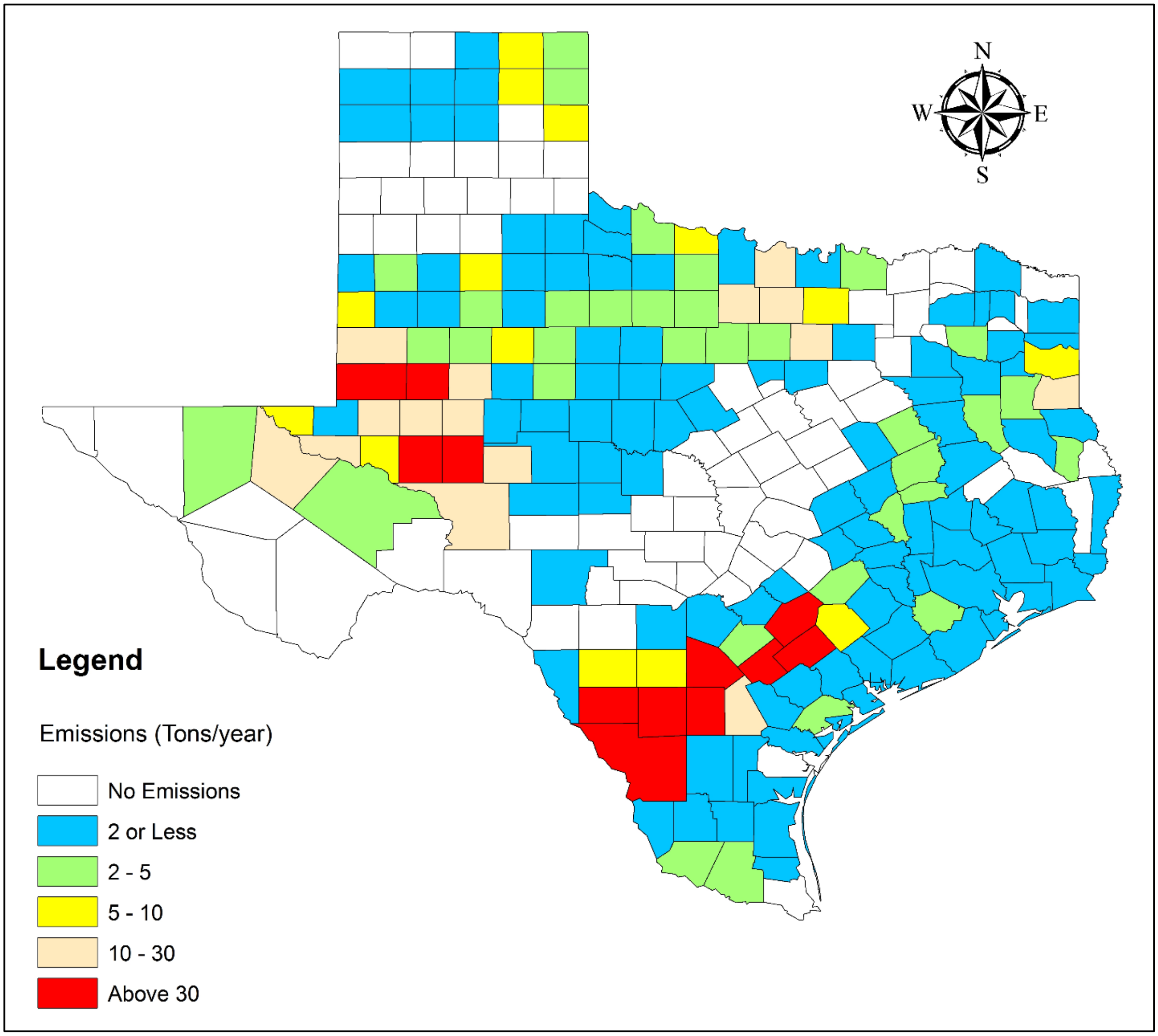


Figure 7-14. 2014 Annual $PM_{2.5}$ Emissions by County (Tons/Year)



7.3.2 CERS XML Files

Once the emissions inventories were completed, CERS XML-formatted input files were prepared. For purposes of XML preparation, SCC 23-10-000-220 (Industrial Processes - Oil and Gas Exploration and Production - All Processes - Drill Rigs) was used, consistent with the 2009 and 2011 studies. ERG uploaded the CERS XML files to the TexAER test server to ensure the files were complete and accurate and in a format consistent with the TexAER area source file data requirements.

7.4 Quality Assurance

ERG conducted a variety of quality assurance checks consistent with the requirements of the Quality Assurance Project Plan (QAPP) submitted to the TCEQ for this project. Key spreadsheet inputs and calculations used to estimate emissions were checked to ensure accuracy, and final emission estimates were evaluated for internal and external consistency. Errors identified during the QA were resolved and emissions estimates were subsequently revised prior to generation of the final XML files developed for TexAER.

QA activities were comprised of two main components – evaluation of the survey data used to generate the updated inventories with respect to reasonableness, and evaluation of the calculation methodologies to ensure the calculations were performed correctly.

First, due to the low response rate to the survey efforts, all external available information that was identified that would help inform the reasonableness of the received data was evaluated. This step is discussed in detail in Section 5.3. This analysis showed that the data obtained through the survey appeared reasonable and was consistent with data developed for other inventory efforts, both within Texas as well as nationally.

Due to the large number of records generated by compiling a 2012 through 2040 inventory for all counties in Texas for over 35 pollutants under both a controlled and uncontrolled scenario, the inventory used to prepare the XML files for TexAER upload was generated using Microsoft Access®. As Task 3.1 of this Work Assignment required updating the Excel-based emissions calculator for the 2014 base year inventory, two independent inventories were generated which allowed for comparison to ensure the emissions were calculated accurately. The Excel-based emissions calculator has been used previously for the 2011 emissions inventory, and was evaluated once the updated emission factors were input and was found to be working correctly. Emission estimates from the Excel-based calculator were then compared to the emissions generated from the Microsoft Access® database and were found to be in agreement. This analysis was done for both the controlled and uncontrolled scenarios and no discrepancies were observed.

Key findings from the evaluation of final emission estimates include the following. First, the time series charts generated for the pollutants appear to follow a reasonable trend for future year projections, with significant activity and emissions drop offs occurring after 2020. The differences in trends across pollutants appear to be explained by the differential impact of emission control phase-in schedules, as discussed in Section 7.3.1 above.

8.0 Conclusions and Recommendations

This study presents updated statewide drilling rig engine emissions inventories for Texas. These inventories were prepared using well drilling activity data obtained through the RRC, combined with updated emissions factors derived through detailed drilling rig engine data collected through a bottom-up survey effort. This study improves upon the 2009 and 2011 inventory efforts by updating drilling rig engine profiles from a 2008 base year to a 2014 base year. In addition, the updated data was evaluated using contemporary information from other similar studies being conducted in Texas as well as nationally. This information was not readily available at the time the 2009 and 2011 studies were prepared.

The ultimate result of this study is a reliable, temporally and spatially resolved profile of county-level drilling activity emissions for the 29 year period from 2012 through 2040. The successful update of the TexAER system with this data will allow for improved SIP and trend analysis for all regions of the state.

Based on the projected oil and gas production levels in Texas from the EIA, drilling activity is estimated to gradually increase across the state through 2020, at which time activity is projected to decline. As shown in the tables and figures presented in this report, the Non-Road diesel engine emission standards have resulted in a steady decrease in drilling-related emissions over time. SO_2 emissions levels in particular are estimated to have fallen precipitously due to the introduction of the ultra-low sulfur standards for diesel fuel in 2010, and should remain extremely low for the foreseeable future.

An analysis of county-level data found that over two-thirds of Texas counties produced some level of emissions associated with drilling activities (180 of 254 counties) in the 2014 base year. However, the county-level distribution of NO_x emissions is highly skewed, with 10 counties being responsible for approximately 50 percent of total statewide NO_x in 2014. In addition, the preponderance of the high NO_x emitting counties were predominantly in West and South-Central Texas where intense drilling activity is occurring in the Permian Basin and the Eagle Ford Shale areas, respectively.

While the emissions inventory results provide an excellent basis for assessing historical emissions levels, projections of future activity are highly uncertain, subject to significant rises and falls depending upon economic factors and associated oil and gas prices. Accordingly, periodic refinement of the activity data used for projected years 2015 through 2040 is strongly recommended to account for such factors.

Finally, while high quality survey data was obtained from several drilling companies in this project, the low number of survey responses could potentially introduce additional uncertainty into the analysis. Fortunately, there are now several other studies with relevant information available that were used to provide data range checks on the resultant drilling rig profiles. The data obtained during the survey were found to agree well with other publically available data and are deemed to be representative of oil and gas well drilling operations in Texas in 2014.

9.0 References

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Appendix A. Drill Rig Emissions (Tons/year)

(see file "Drill Rig Emissions.xlsx")

Appendix B. Survey Letter

Dear Owner/Operator:

Eastern Research Group (ERG), an independent research organization, is conducting a study on **drilling rig engine** emissions for wells drilled in Texas in 2014 for the Texas Commission on Environmental Quality (TCEQ). Information currently used by TCEQ to develop emission estimates for drilling rig engines is based on older data collected in 2009. Since that time, it is expected that newer, more efficient engines have been brought on-line and emissions associated with well drilling have decreased. Therefore, the goal of this study is to obtain more current information reflecting operating practices (such as the hours of operation) and drilling rig configuration (such as the age, number, and size of engines) used during well drilling.

Your participation is voluntary and completely confidential, individual wells do not need to be identified. The information your company provides will be used for statistical purposes only in order to develop basin-level estimates and will not be republished or disseminated for other purposes. Responses will not be disclosed in identifiable form to anyone other than ERG employees or agents.

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 drilling rig engine usage information for oil and gas wells your company drilled in the [Insert Basin_name] basin located in [Insert counties_text]. The specific information we are requesting for each basin is provided on the reverse side of this letter. Your expertise is valued; please contact us with any comments or clarifications!

Your response is requested by **May 29, 2015**. Completed forms may be submitted via email to **Len Boatman** at 2014drillingsurvey@gmail.com, or via fax to **(512) 419-0089**. For further information or assistance in completing this form, please call Len Boatman at (346) 444-5097.

We appreciate your assistance in this important study. 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. If you have any specific questions on the technical aspects of this study, please feel free to contact me at (919) 468-7840, or via email at mike.pring@erg.com.

Sincerely,

Mike Pring
Senior Environmental Engineer
Eastern Research Group, Inc.

DRILL RIG SURVEY QUESTIONS

Part 1. General Information

Owner/Operator	
Owner/Operator Contact Name	
Owner/Operator Contact Phone	

Please use **county or basin** averages for each question.

1. Well Locations (county or basin)	
2. Well Type (vertical, horizontal, directional) [a]	
3. Well Measurement Depth (feet)	
4. Well Horizontal/Lateral Length (feet) [b]	
5. Well Drilling Duration (days)	
6. Rig Type (Mechanical or Electric/SCR)	
7. Number of engines on site	
8. Rig Fuel Use (gallons diesel/day)	

[a] Use a separate form for each well type.
[b] Include lateral length for horizontal wells.

Part 2. Drill Rig Engine-Specific Information (for each engine to complete a typical well).

Engine Function (Draw works, Mud Pump, Generator)	Engine ID	Make and Model	Model Year	Engine Size (HP)	Engine On-time (hr/day)	Engine time under load (hr/day)	Engine Load (%)

Comments:

Appendix C. Drill Rig Survey Results

(see file “Drill Rig Survey Results.xlsx”)

Appendix D. Drill Rig Emission Factors

(see file “Drill Rig Emission Factors.xlsx”)

Appendix E. 2015 – 2040 Projected Drilling Activity

(see file “2015_2040 Projected Drilling Activity.xlsx”)