EXHIBIT 4

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Final Report

WRAP AREA SOURCE EMISSIONS INVENTORY PROECTIONS AND CONTROL STRATEGY EVALUATION PHASE II

Prepared for

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PREFACE

Regulatory Framework for Tribal Visibility Implementation Plans

The Regional Haze Rule explicitly recognizes the authority of tribes to implement the provisions of the Rule, in accordance with principles of Federal Indian law, and as provided by the Clean Air Act (CAA) §301(d) and the Tribal Authority Rule (TAR) (40 CFR §§49.1– .11). Those provisions create the following framework:

1. Absent special circumstances, reservation lands are not subject to state jurisdiction.

2. Federally recognized tribes may apply for and receive delegation of federal authority to implement CAA programs, including visibility regulation, or "reasonably severable" elements of such programs (40 CFR §§49.3, 49.7). The mechanism for this delegation is a Tribal Implementation Plan (TIP). A reasonably severable element is one that is not integrally related to program elements that are not included in the plan submittal, and is consistent with applicable statutory and regulatory requirements.

3. The Regional Haze Rule expressly provides that tribal visibility programs are "not dependent on the strategies selected by the state or states in which the tribe is located" (64. Fed. Reg. 35756), and that the authority to implement §309 TIPs extends to all tribes within the GCVTC region (40 CFR §51.309(d)(12).

4. The EPA has indicated that under the TAR tribes are not required to submit §309 TIPs by the end of 2003; rather they may choose to opt-in to §309 programs at a later date (67 Fed. Reg. 30439).

5. Where a tribe does not seek delegation through a TIP, EPA, as necessary and appropriate, will promulgate a Federal Implementation Plan (FIP) within reasonable timeframes to protect air quality in Indian country (40 CFR §49.11). EPA is committed to consulting with tribes on a government to government basis in developing tribe-specific or generally applicable TIPs where necessary (See, e.g., 63 Fed. Reg.7263-64).

The amount of modification necessary will vary considerably from tribe to tribe. The authors have striven to ensure that all references to tribes in the document are consistent with principles of tribal sovereignty and autonomy as reflected in the above framework. Any inconsistency with this framework is strictly inadvertent and not an attempt to impose requirements on tribes which are not present under existing law.

Tribal Participation in the WRAP

Tribes, along with states and federal agencies, are full partners in the WRAP, having equal representation on the WRAP Board as states. Whether Board members or not, it must be remembered that all tribes are governments, as distinguished from the "stakeholders" (private interest) which participate on Forums and Committees but are not eligible for the Board.

Despite this equality of representation on the Board, tribes are very differently situated than states. There are over four hundred federally recognized tribes in the WRAP region, including Alaska. The sheer number of tribes makes full participation impossible. Moreover, many tribes are faced with pressing environmental, economic, and social issues, and do not have the resources to participate in an effort such as the WRAP, however important its goals may be. These factors necessarily limit the level of tribal input into and endorsement of WRAP products.

The tribal participants in the WRAP, including Board members Forum and Committee members and co-chairs, make their best effort to ensure that WRAP products are in the best interest of the tribes, the environment, and the public. One interest is to ensure that WRAP policies, as implemented by states and tribes, will not constrain the future options of tribes who are not involved in the WRAP. With these considerations and limitations in mind, the tribal participants have joined the state, federal, and private stakeholder interests in approving this report as a consensus document.

An adjunct study of oil and gas emissions point and area source emissions was conducted by ENVIRON and ERG. Oil and gas emissions for four tribes were inventoried: Wind River Reservation, Ute Mountain Ute Tribe, Navajo Nation, and Jicarilla Apache Nation. Emissions sources for the Jicarilla Apache Nation were inventoried, but they elected to not formally participate in the project. The final project report, *Point Source and Oil and Gas Area Source Emission Inventories on Native American Reservations and Tribal Lands* (ERG/ENVIRON, 2005), does not include Jicarilla Apache data.

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1. INTRODUCTION

Background

In 2002, more than 5.6 trillion cubic feet of natural gas and 1.15 billion barrels of crude oil were drawn from oil and gas wells in the 14 western states (EIA, 2006a, EIA, 2006b). In 2005, those numbers were 6.4 trillion cubic feet of natural gas and 1.1 billion barrels of crude oil (US DOE, 2007). To achieve this level of production, an extensive fleet of oil and gas production equipment operates continuously across the Western U.S. The sizes and types of equipment in that fleet vary from small chemical injection pumps up to gas turbines of several thousand horsepower. Despite their differences, at least one common feature unites many of these equipment types. They emit nitrous oxides (NOx), volatile organic compounds (VOC) and other air pollutants as part of their normal daily operations. Even the smallest of these source types generate significant emissions when the continuous operation and the number of units are taken into consideration. Previous emission inventories have addressed limited segments of the oil and gas production industry. In particular, large oil and gas facilities have been well accounted for in state point source inventories. Thus this inventory represents an effort to create a more systematic, region-wide emissions inventory for oil and gas area sources in the western states of the U.S.

This inventory represents the second phase of a region-wide inventory of oil and gas area sources in the Western U.S. Prior to the first phase of this work, the only significant emissions inventory efforts to address oil and gas area source emissions were a statewide inventory in Wyoming (Pollack, A.K.; Russell, J.; Rao, S.; Mansell, G., 2005), a statewide oil and gas emissions inventory in California that identified some minor wellhead processes (CARB, 2007a), and some focused studies by the New Mexico Oil and Gas Association (NMOGA) in northwestern New Mexico (NMOGA, 2003). Thus the WRAP Phase I emissions inventory represented the first time that a region-wide estimate was made of oil and gas area sources (Russell, J.; Pollack, A., 2006). That inventory focused on drilling rigs, compressors, coal bed methane pump engines, and minor NOx sources such as heaters, tanks, glycol dehydrator units and pneumatic devices. Due to the limited availability of regional-specific data, the Phase I emissions inventory was regionally uniform in terms of activity source type (e.g., compressor engine size distribution) and so associated emission estimates were more uniform by the number and types of engines.

Following the original Phase I emissions inventory, the New Mexico Environment Department (NMED) funded a detailed study of oil and gas area sources in northwestern New Mexico to establish a revised emissions inventory for oil and gas area sources in San Juan and Rio Arriba counties (Pollack, A.; Russell, J.; Grant, J.; Friesen, R.; Fields, P.; Wolf, M. 2006.). For this emissions inventory effort, a survey questionnaire was developed to obtain detailed information on oil and gas operations directly from the major producers in these counties. The companies responding to this survey collectively owned and operated about 60 percent of the wells in these two counties. Because significant resources were available to conduct a detailed equipment-specific inventory for these two counties, this approach was much more accurate than the emissions for these two counties in the WRAP Phase I project.

Based on these previous emissions inventory efforts, WRAP contracted with ENVIRON to provide an updated Phase II WRAP region-wide emissions inventory of oil and gas area sources to be used in regional haze modeling for states' regional haze SIP compliance. ENVIRON was tasked only to estimate oil and gas *area* sources, while point source emissions were developed through a separate inventory effort.

Objectives and Approach

The methodologies and results presented in this report are the result of a second phase of emissions inventory analysis that builds upon the Phase I work conducted in 2005-2006. The goal of the project was to improve upon the original WRAP area-wide inventory, by updating the methodology used to generate the emissions inventory, updating information on control strategies, and updating the 2018 emissions projections including the impact of the control strategies on these emissions. The specific tasks addressed in this new inventory analysis were:

1) Improvements to the 2002 Emissions Inventory - This task focused on improving estimates of the emissions inventory of NOx, SOx and PM from O&G operations. These criteria pollutants can have serious potential health consequences, are smog-forming precursors, and can negatively impair visibility. The most significant emissions of NOx in the WRAP regions are from drill rigs and from natural gas-fired compressor engines. The most important sources of SOx and PM emissions are from drilling rig engines, and from minor H2S emissions in some O & G operations in southwest New Mexico. Some effort was made to distinguish between emissions from conventional gas wells and coal bed methane (CBM) gas wells as these are expected to have some differences. Work focused on drilling rigs, gas compressor engines, CBM operations.

2) Updating Baseline Emissions from 2002 to 2005 – Calendar year 2005 wells and production data were available from state Oil and Gas Commissions (OGCs), and were used to estimate O&G area source emissions in 2005. This estimate provides a more current year of emissions inventory results, with emissions matched to more current activity levels, and served as the basis from which to project the 2018 emissions. The approach used to generate 2005 emissions was to first revise the 2002 emissions using methods discussed below for specific source categories, to generate county-level emissions using this methodology, and then to scale up the revised 2002 county-level emissions to 2005 using county-level 2005/2002 OGC production and/or well count data. The choice of production or well count data for scaling was made for each process separately, based on which type of data was the basis for the revised 2002 emissions calculations

3) Control Strategy Evaluation – Potential control strategies for drilling rigs and compressors were identified and a series of white papers developed that provide a detailed description of these control technologies. The white papers contain an analysis of the emissions reduction potential, the cost and cost-effectiveness of NOx reductions from control measures aimed at compressor engines and drilling rigs, and to a limited extent from VOC sources involved in exploration and production of natural gas. Control strategies identified include engine modifications, emissions control retrofit technology, and modernization of equipment through repowering or replacing engines. The application of a mix of control measures to the San Juan Basin in New Mexico, with

assumed penetration rates for each measure for drilling rigs and compressors, is presented as an example of the methodology for investigating the emissions reduction potentials and cost of a controls scenario.

4) 2018 Emissions Forecasts - The Phase I 2018 oil and gas emissions estimates were developed by projecting 2002 emissions based on a combination of production data and well count data. The objective of this task was to review these sources of data, utilize new sources of data if available, and then conduct projections of the 2005 county-level emissions to 2018. The projections were developed from regional production forecasts in the Annual Energy Outlook (AEO) generated by the Energy Information Administration (EIA)3, from local Resource Management Plans (RMPs) in specific geographic areas, from Environmental Impact Reports/Statements (EIR/S) for specific areas, and any other available local and regional planning documents. The objective was to use these data sources to project uncontrolled 2018 emissions, except for the incorporation of "on-the-books" controls that have already been enacted by some states.

5) Improvements to Point Source SOx Emissions in 2018 - The objective of this task was to revise the emissions of SOx from large point sources due to oil and gas operations in the WRAP region in 2018. These point sources are primarily natural gas processing plants located in Wyoming and New Mexico. Previous projections of these plants' SOx emissions have not included recent advances in SOx removal technology that oil and gas producers have been increasingly utilizing to reduce SOx emissions from these sources. The approach used was to revise the control assumptions, and more importantly to develop the projection factors based on the 2018 production projections that were developed as part of task 3 above.

The discussion of these five tasks in this report is organized chronologically: it begins with the 2002 emissions inventory update for select source categories; next the 2002-to-2005 scale up of emissions is presented; the evaluation of control technologies is presented in the white papers for each control measure considered; the projections from 2005 emissions to 2018 emissions are discussed; and finally the methodology and revised 2018 SOx point source emissions are discussed. Each section describes the detailed methodology used and present the quantitative results. The final section describes the resulting western U.S. oil and gas area source emissions inventory for all of the states considered here.

The resulting inventory differs significantly from the Phase I inventory. The major differences between the Phase I and Phase II inventories are the improved activity and equipment information in the Phase II inventory, for both drilling rigs and compressors. More detailed information was provided by producers on emissions factors for specific equipment types, however because the project resources were limited not all pollutants were addressed. All updated information from the producers was provided on a geographically specific basis, thus those geographic areas which were updated in this Phase II inventory have more accurate emissions predictions than those areas which remained unchanged from the Phase I inventory.

Limitations of this Inventory

Although this Phase II inventory represents an improvement over the Phase I inventory, there are some limitations to the scope of this inventory:

- Not all pollutants from oil and gas area source categories were evaluated. For the drilling rigs and compressors which were the focus of this inventory, not all pollutant emissions from these two equipment types were considered. PM, HC and CO emissions factor information for all engines were not available for every engine identified, and given the wide range of engine sizes and ages considered it was determined that insufficient information was available to estimate PM, HC and CO emissions from some of these engines. Emissions of NOx were considered the focus of this inventory.
- Detailed lists of equipment could not be identified for all focus geographic regions. In some areas, only a small number of equipment types were identified from producer data and broad assumptions needed to be made about this equipment.
- In some geographic regions activity data was more detailed than others. Information about the frequency of maintenance activities, or emergency or mechanical down-time for equipment was not always available. A greater response from producers may resolve this issue in any possible future inventory.
- Some geographic areas were not considered. Although the aim of the Phase II inventory was to identify and assess all geographic areas of major oil and gas activity, some areas were not considered. Due to the limited resources available for surveying producers, the oil and gas producing basins in Montana and North Dakota were not part of the focused regions that were considered, and the Phase I emissions estimates for these areas were carried through. Information about oil and gas activity in Alaska was not easily available and it would entail significant resources and effort to estimate activity there, so Phase I estimates were carried forward.
- Not all major sources of NOx were updated in the Phase II work. As noted above, compressor and drilling rig NOx emissions were the focus of the Phase II project. Heaters used to provide heat for separators or tanks were not updated and the Phase I estimates for heater emissions were carried forward. Other minor NOx sources such as flares and completions were not inventoried in the Phase II work.
- VOC emissions are incomplete and were not specifically updated in this Phase II work. VOCs were estimated in the Phase I work from tanks, glychol dehydrators, pneumatic devices and flaring and venting, however these estimates could be greatly improved. In the NMED inventory for San Juan and Rio Arriba counties, the VOC emissions for oil and gas area sources were 52,000 tons per year greater than the Phase I inventory for these same two counties, which represented a 98 percent increase in VOC emissions. The Phase I work also did not consider some VOC source categories such as flaring and breathing losses.
- Hazardous air pollutants were not considered. Hazardous air pollutants (HAPs) were not considered in this inventory for any source category.
- PM emissions from combustion and fugitive dust were not considered. PM emissions factors from direct combustion were difficult to find for all engine types, and activity and other information needed to estimate fugitive dust emissions were not available.
- Greenhouse gas emissions were not estimated. Emissions of CO2 and methane were not estimated for this Phase II inventory.

Further details on what is and is not included in this Phase II oil and gas area source emissions inventory are provided in the report.

Political Jurisdictions

In the Phase II inventory effort, emissions were estimated on a county basis (using basin-specific information), and summed to obtain state-wide emissions. The emissions in this report are presented on a state-wide basis. Basins are often located in more than one state. Some counties lie within more than one basin, and in such cases the county emissions were divided among the appropriate basins on the basis of the available information – either well count in the county or gas and oil production in the county. In all cases, the equipment and activity of that equipment were considered uniform within a basin. No effort was made to track the movement of equipment from one basin to another.

The Phase I inventory separated out emissions from wells on tribal lands – this Phase II inventory did not separate out tribal emissions. These emissions are included in the state-wide oil and gas area source emissions totals.

Point vs. Area Sources

This Phase II inventory, similarly to the Phase I inventory, includes only oil and gas area sources. Point sources were not considered in this inventory, as they are analyzed and inventoried separately. In order to determine what would be included in a state's point source inventory, ENVIRON examined the state-by-state emissions thresholds that trigger reporting in a state's point source inventory. This differed from state to state; however for most states the assumption that wellhead compressors were not in the point source inventory was a reasonable one. The only two states for which this rule does not apply are Colorado and Alaska. In Colorado, the point source inventory reporting threshold is 2 tons per year of NOx. This state point source inventory was therefore assumed to include all compressors, including wellhead compressors. ENVIRON made no further effort to inventory these sources in Colorado, in an effort to avoid double-counting with Colorado's point source inventory. Compressor stations in Alaska operate in a hub-and-spoke system, in which the small wellhead compressors are associated with the large central compressor stations they serve. Therefore in Alaska all wellhead compressors emissions were included in the point source inventory of the major compressor stations. The report shows both area source and point source oil and gas emissions totals for each state in the WRAP region for 2002 in Section 2, and for 2018 in Section 5.

2. 2002 EMISSIONS INVENTORY IMPROVEMENTS

The focus of the 2002 emissions inventory improvements was on NOx and SOx emissions from oil and gas (O&G) area sources. The most significant emissions of NOx in the WRAP region are from drill rigs and from natural gas-fired compressor engines. The most important sources of SOx emissions are from drilling rig engines, and from minor H_2S content in natural gas that is combusted. There are additionally some minor SOx emissions from coal bed methane (CBM) wells' pump engines in New Mexico where H_2S is sometimes present.

Prior work in the WRAP region was limited by available information and accordingly, certain assumptions about O&G production were improved upon. The Phase I work made estimates of drilling time and activity on the basis of state Oil and Gas Commissions (OGCs) databases, which did not provide enough detail for an accurate calculation of actual drilling times. Drilling rig engine loads were assumed to be at the maximum capacity for that engine, and a similar assumption was made for compressors. Actual loads vary significantly with the type of O&G operation being considered and vary widely particularly for compressor engines. An inventory project for the New Mexico Environment Department (NMED) focused on improving these estimates and assumptions, but studied only O&G operations in San Juan and Rio Arriba counties in northwest New Mexico (Russell, J.; Pollack, A., 2006). Thus this work was limited to the types of operations in this geographic region. The analysis presented here focuses on expanding the types of revised estimates made in the NMED work to other WRAP producing regions, as well as incorporating more recent information from O&G producers in the WRAP region on their specific utilization of drilling rigs and gas compressors in their O&G operations. The revised estimates make use of information about the geography of the O&G operations and the producers' specific operations.

Field/Basin Information

Given the geographic size of the WRAP region, a new methodology was developed that both makes use of geographically-specific equipment and activity assumptions, and generalizes these assumptions in a tractable way. Activity, equipment and emissions were assumed to be uniform throughout a geologic basin, and estimates of emissions were then conducted separately for each basin in the WRAP region in which major O&G activity was occurring.

A structural basin is a large-scale structural formation of rock strata formed by tectonic warping of previously flat lying strata (Monroe, J.S.; Wicander, R.. 1997). Structural basins are synonymous in some ways with geological depressions (Monroe, J.S.; Wicander, R.. 1997). Within a basin are potentially many oil and gas producing fields where drilling is occurring and wells are sited. Grouping equipment and emissions by field would be intractable as there are literally thousands of active fields in the western United States – and thus the analysis was made by grouping activity, equipment and emissions by basin.

Another significant update in this analysis compared to the prior work is that information was obtained directly from the O&G producers to better identify the basins where major O&G operations were occurring and to obtain specific activity and equipment details of those operations. Based upon the information supplied by producers, the emission inventory efforts were focused on those areas where significant production is occurring and where a significant potential existed to improve the inventory. The basins in which significant O&G activities were occurring in 2002 and 2005 are:

- Wyoming: Southwestern Wyoming (Green River) Basin; Wind River Basin; Big Horn Basin; Powder River Basin
- Colorado: Denver-Julesburg Basin; Uinta-Piceance Basin; San Juan (North) Basin
- Utah: Uinta-Piceance Basin; Paradox Basin
- New Mexico: San Juan (South) Basin; Permian Basin

These basins include the Four Corners region, Southeast New Mexico, Utah, Colorado, Southwest Wyoming, North Central Wyoming, and Northeast Wyoming. Figure 2-1 shows the basins in the WRAP region and highlights the focused basins. The Big Horn and Powder River basins in Wyoming also cover active regions in Montana that lie within these basins. Idaho, Washington, Oregon, Nevada and Arizona were not a focus of this emission inventory analysis because O&G operations occurring in these areas are less significant. California was not included in this analysis because O&G operations have been traditionally inventoried and regulated through the California Air Resources Board (CARB). Alaska represents a special case. Most oil and gas production in Alaska occurs at large centralized stations that are considered point sources and have been included in point source inventories. Where wellhead equipment is used, it is typically arranged in a "hub-and-spoke" configuration that ensures that it is included in the permitted equipment of the large central gas processing station (the "hub"). Thus for Alaska the only major area source category that was considered was drilling rigs.

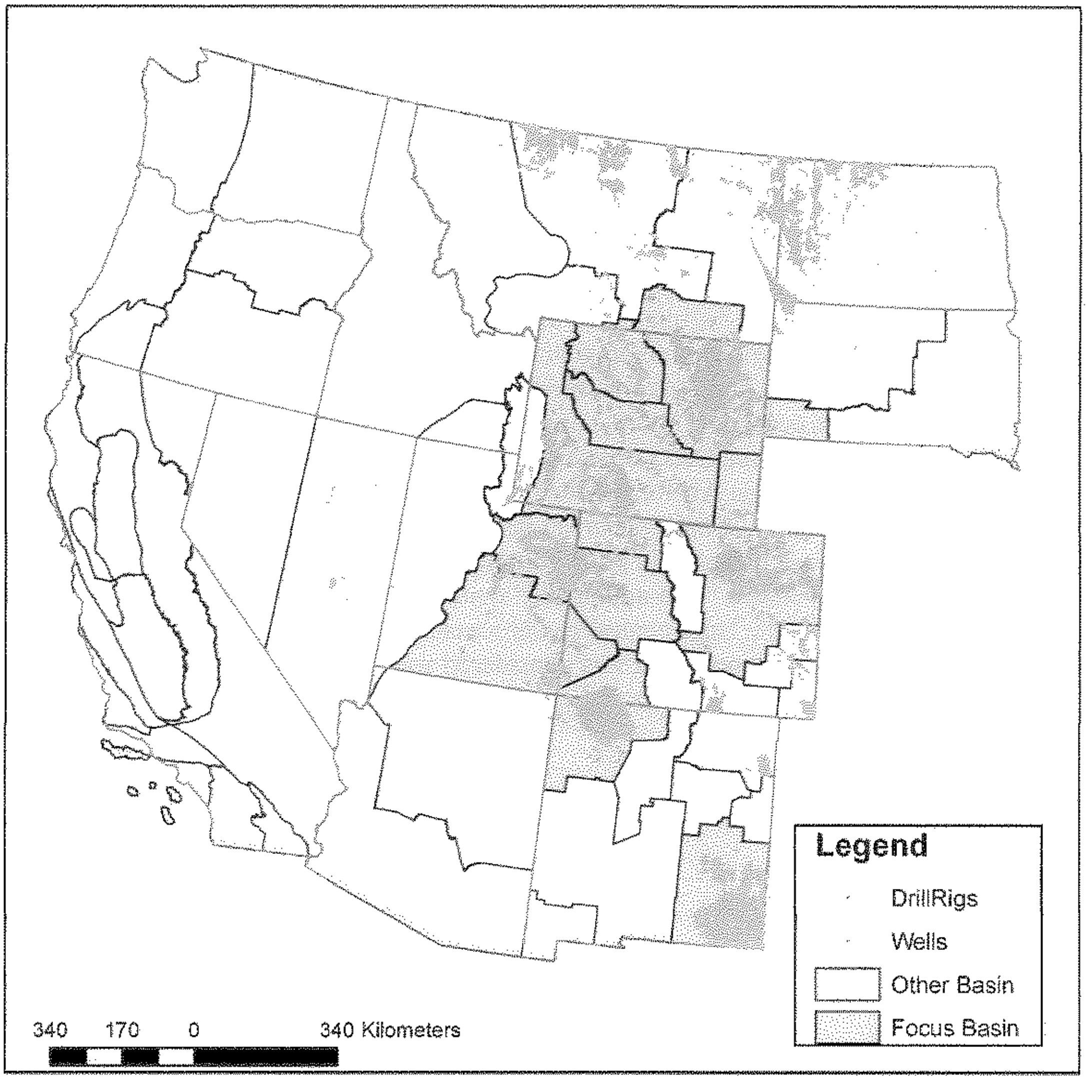


Figure 2-1. Oil and gas producing wells and drilling sites in the western regional U.S., and production basins and focus basins in the western regional U.S.

The methodology involved collecting producer information on specific basins where the producer has significant operations. Each producer provided detailed information for the basin where they operate, and these data were used to estimate overall average characterization of O&G operations and emissions in each basin. Where multiple producers were operating extensively in a single basin, each producer's detailed information was used to create a weighted average of activity based on each producer's well count in the basin as a fraction of the total well count.

The database of well-specific information from state OGC's that was developed in the Phase I analysis for 2002 was used to identify basin boundaries and the well counts within each basin. These basins were then intersected with county lines to determine the fraction of each county in the WRAP region that lies within a focus basin. It should be noted that where specific information on operations in a basin was not available, the emissions estimate from the Phase I analysis were used.

Drilling Rig Emissions

The WRAP Phase I approach developed to estimate emissions from drill rig engines used drill permit data from oil and gas commissions (OGCs) as a measure of activity and emission factors derived from a survey of drilling companies. The drill permit data were used to determine the drilling time and drilling depth, as well as a total count of wells drilled in 2002. The survey of drilling companies yielded results for representative equipment in only one region – the Jonah-Pinedale area of the Green River Basin in Wyoming. Given this lack of data, it was necessary to scale equipment emissions factors and horsepower from the Jonah-Pinedale study by well depth and drilling time to other fields, introducing potential inaccuracy to the emissions estimates. Another source of inaccuracy was the drilling times derived from the state OGC databases. These databases recorded the spud date – the date when drilling begins – and the completion date of the well when production begins. However, drilling occurs during only a fraction of that time, with the remainder of that time being reserved for well completion activities. This fraction varies widely by geographic location, and is generally a function of the type of rock in which the drilling occurs, and the depth of the drilling. The use of a single drilling time fraction in the previous analysis introduced inaccuracy to the emissions calculations. Furthermore, due to lack of information, the Phase I analysis assumed that all drilling rigs operate at 100% engine load.

Thus there were several aspects of the drilling rig emissions estimates that could potentially be improved in the Phase II analysis. The NMED work improved these estimates for northwest New Mexico by obtaining drilling stop times from operators in this region (rather than well completion times), by obtaining actual horsepower and emissions factors characteristics of each engine inventoried, and by derating the maximum power of the engine to account for well depth. Also, the NMED work made use of emissions testing conducted on three representative drilling rig engines manufactured by Detroit Diesel to derive representative emissions factors for drilling rigs.

The current analysis leveraged the additional information provided directly by producers. Producers were asked to provide details of the operational and equipment characteristics of drilling rigs as part of the survey of producers, which specifically asked:

1) What are the actual average drilling times (start drilling to stop drilling dates) for wells in the basin?
2) What is the average depth of wells drilled in the basin?
3) What is the actual average load factor of the drilling rig engines operating in the basin?
4) What is the average horsepower of drilling rig engines operating in the basin?
5) Please identify a representative make and model of drilling rig engine (or up to 3 representative makes and models) that are most frequently used in the basin.
6) What are the measured or manufacturer's rated emissions factors for the drilling rigs identified in (5) above?
7) What type of fuel is used in these drilling rigs, and can the exact sulfur content of that fuel be provided?
8) What is the fuel consumption of a representative make and model of drilling rig as it drills to an average well depth for an average duration?

This information allowed for an improved estimate of actual drilling stop times and drilling horsepower needs. Average drilling times, depths and horsepower were used to derive a representative basin average emissions per well drilled. This corrected for any potential errors in drilling time estimates made in the Phase I where the drilling times were extrapolated as a function of total well preparation time from only the Jonah-Pinedale region. The producers contacted as part of the current analysis have indicated that the Jonah-Pinedale area may not be representative of drilling needs and activities at other locations. Based on information obtained from producers and the NMED analysis, actual drill times and therefore drilling emissions may have been overestimated because drilling rigs are removed from operation once a desired well depth has been reached. Any remaining operations at the well are handled by well completion equipment. For the San Juan Basin in New Mexico, the detailed NMED analysis was used directly because it was deemed to be more accurate than the basin-average methodology described here (Pollack, A.; Russell, J.; Grant, J.; Friesen, R.; Fields, P.; Wolf, M. 2006).

Based on specific information obtained from producers, it was determined that the drilling horsepower requirements are based upon the anticipated drilling depth and drilling time, rather than by the formation type. The load factors used for drilling rig engines in previous estimates were improved upon based on specific information from producers. The information provided by producers indicated that the 100% load assumed in the Phase I work was incorrect and that in fact drilling rig engines are often operated at loads of approximately 50% due to the fact that the engine is overpowered for the drilling application. Where information was available from producers about drilling engine load factors, those factors were used. The producers also provided a representative engine configuration for up to three most commonly used drilling rigs in each basin. If more than one representative drilling rig configuration was cited, emissions were estimated for the representative well for each rig and averaged. This represented a substantial improvement over previous estimates because it was found that drilling rigs are often composed of multiple engines, each performing different tasks for different lengths of time and different engine loads, as well as having different emissions factors for each engine (Flanders, C., 2007). Some drill rigs are made up of as many as four engines: two draw-works engines that control the drill string, one mud pump engine that controls all pumping activity, and one generator engine to provide electrical power.

The general procedure for estimating drilling rig emissions was to develop a representative emissions estimate per well in a basin. The average depth of wells in a basin was obtained from producers, and a weighted average well depth was derived for each basin, where the weighting factors were the number of wells that each producer operated in that basin. The same procedure was used for the actual drilling times as reported by producers. This information was combined to derive an average emissions per well for a basin according to Equation 2-1.

Equation 2-1:

$$E_{basin,avg} = \sum_i LF_i \times HP_i \times DF_i \times EF_i \times t_{i,drilling}$$

where $E_{basin,avg}$ is the emissions of the basin average well of a particular pollutant [tons/well], i is a particular engine on a drill rig (e.g. draw works, mud pump), LF_i is the load factor of engine i on a drill rig [%], HP_i is the horsepower of engine i on a drill rig [hp], DF_i is the deterioration factor of engine i on a drill rig, EF_i is the emissions factor of a particular pollutant of engine i on a drill rig [g/bhp-hr], and $t_{i,drilling}$ is the total drilling time (or fraction of total drilling time) of engine i on a drill rig [hr].

The emissions factors for NOx, SOx, VOC and CO were obtained from a variety of sources. In some instances the producers had direct measurements of the emissions factors of in-use equipment and provided these. In other instances the manufacturers rated emissions factors for a specific engine model and horsepower were used. If manufacturers rated emissions factors were used, it was necessary to account for deterioration of the equipment and the assumption was made that the equipment would be fully deteriorated as indicated by the manufacturers. The deterioration factors are a direct multiplier of the emissions factors, and were determined by using the deterioration model contained in the U.S. EPA's NONROAD2005 model for diesel non-road equipment (EPA, 2005a). It was assumed that the deterioration factors were those of baseline (or Tier 0) equipment – that is, before the introduction of federal standards regulating non-road engine emissions (EPA, 2005b). This is consistent with producer information indicating that drilling rigs are in service for many years before being upgraded, or rebuilt, at which point their emissions characteristics would be expected to change. However, the issue of deterioration factors should be further investigated in any future emissions inventory effort. The deterioration factors for each pollutant are shown in Table 2-1.

Table 2-1. Deterioration factors for drilling rig engines from EPA's NONROAD2005 model.

Pollutant	Deterioration Factor[a]
NOx	1.024
VOC	1.047
CO	1.185
PM	1.473

a - Note that deterioration factors are applied to the Tier level of each engine type for purposes on calculating emissions

The emissions factors for SOx were not subject to deterioration, as they are a direct function of the sulfur content of the fuel. The sulfur content of the fuel was determined from a survey conducted by WRAP in which individual counties responded with information about seasonal sulfur content in the non-road diesel fuel (Pollack, A.; Chan, L.; Chandraker, P.; Grant, J.; Lindhjem, C.; Rao, S.; Russell, J.; Tran, C., 2006).

Using the state OGC database of all wells drilled in 2002 and the depths to which the wells were drilled in the basin, $E_{basin,avg}$ was scaled on the basis of depth for each well in the basin and summed to obtain the total basin emissions from drilling rig activities. This calculation is shown below in Equation 2-2.

Equation 2-2:

$$E_{basin,total} = \sum_j E_{basin,avg} \times \left(\frac{d_j}{d_{avg}} \right)$$

where $E_{basin,total}$ is the total drilling rig emissions in a basin [tpy], $E_{basin,avg}$ is the emissions from an average well in the basin [tons/well], j is a well in the basin, d_j is the depth of well j in the basin [ft], and d_{avg} is the depth of an average well in the basin [ft]. The variation in depth of wells in a basin will affect the duration of drilling activity for each well. By using the producer reported average well depth and scaling this by the actual well depth of other wells, this methodology corrects for the varying drilling times of all wells in a basin.

The location of individual wells in a basin is determined on a county level, and the emissions totals for the basins are apportioned to each county in the basin on the basis of drilling spud count in that county. In some instances, counties are completely located within a basin. In other instances, portions of the county may be located in another focus basin, or in a basin for which no revised 2002 emission inventory estimates were made. In such a case the fractional spud count in the focus basin is used to determine the fraction of the county's emissions that are updated using this methodology. Finally, all counties in a state are summed to generate state total emissions from drilling rigs.

Table 2-2 summarizes the results of this analysis for all states in the WRAP region, which includes New Mexico, Arizona, Nevada, California, Utah, Colorado, Wyoming, North Dakota, South Dakota, Montana, Idaho, Oregon, Washington, and Alaska. California, as mentioned above, was excluded from this analysis. No drilling activity occurs in Idaho or Washington. As can be seen in Table 2-2, by far the largest NOx emissions from drilling activities are in New Mexico and Wyoming with Colorado following. North Dakota and Montana both have greater than 1,000 tons per year NOx emissions from drilling in 2002. SOx emissions do not correlate directly to NOx emissions – for example in Wyoming SOx emissions are 150 tons per year, less than half those of North Dakota – although North Dakota has three times less NOx emissions. The SOx emissions are driven both by drilling activity and the sulfur content of the non-road fuel in that state. In Wyoming, some efforts have been made to begin regulating the use of low-sulfur diesel fuel for non-road applications.

Table 2-2. Drilling rig emissions by state in the WRAP region in 2002.

State	Drill Rig Emissions [tpy] NOx 2002	SOx 2002	VOC 2002
Alaska	877	66	0
Arizona	0	0	0
Colorado	2,803	118	101
Montana	1,046	225	0
Nevada	24	1	0
New Mexico	5,476	244	68
North Dakota	1,536	358	0
Oregon	0	0	0
South Dakota	29	6	0
Utah	334	17	12
Wyoming	4,997	150	228
WRAP Total	17,123	1,185	410

Wellhead Gas Compressor Engine Emissions

The focus of the area source compressor engine emission estimate was the group of relatively small, dispersed wellhead compressor engines. The Phase I work represented the first effort to inventory these engines in most of the western states included in the WRAP region. Only two of the natural gas producing states had made previous efforts to inventory wellhead compressor engines. The results of the Phase I work indicated that these engines were a major contributor to the total O&G area source NOx emissions, and thus were one of the two sources updated in this analysis.

The Phase I work estimated emissions from compressor engines by generating a production-based emission factor from a local study of compressor engine emissions conducted by the New Mexico Oil and Gas Association (NMOGA) in the San Juan Basin of Northern New Mexico. The WRAP regional wellhead compressor emissions totals for each state were generated by scaling this production-based emissions factor by local gas production statistics. Implicit in this analysis were assumptions regarding the usage of wellhead compressors at individual well sites, based upon the fractional usage in the San Juan Basin.

The current analysis reviewed the previous Phase I methodology, and made use of the survey sent to major O&G production companies to compile basin-by-basin information about wellhead compressors and their emissions. The goal of this methodology was to move from a production-based emissions factor (EF) to a well count-based EF. This was considered more accurate because a count-based EF allowed for a calculation of emissions that used activity information about the engine, including the expected load in a basin, as well as accounting for variations in the equipment and typical configuration in each basin. In order to develop count-based wellhead compressor emissions estimates, it was necessary to determine the number of wellhead compressors in each basin as a fraction of the total number of wells in that basin. The specific information on wellhead compressors requested from major O&G producers in the survey was:

1) How many wells does the producer operate within each basin in which they operate (number of wells and in which basin these wells are located)?
2) What fraction of the number of wells in each basin in which the producer operates use wellhead compressors, what fraction use lateral compressors, and what fraction use centralized compressors?
3) What is the average load on a wellhead and/or lateral compressor engine as a basin-wide average for each basin in which the producer operates?
4) What are the three most commonly used makes and models of wellhead and/or lateral compressors in each basin in which the producer operates?
5) What are the manufacturers' rated emissions factors of NOx, CO, and VOC for each of the makes and models of compressor engines identified?

Based on the responses of producers, and detailed conversations with each major producer, it was determined that wellhead compressor usage, equipment type, and typical operating load vary widely from basin to basin. Thus the Phase I assumption of a single production-based EF using San Juan Basin information was determined to be inaccurate. The San Juan South Basin in New Mexico has a high fraction of well-head usage whereas other basins did not – this is mainly driven by the need for well-site compression to boost field pressures sufficiently for transmission to pipelines. In virgin or newly developed fields and basins the field pressures are sufficiently high that far fewer wellhead compressors are required to generate this pressure than in mature fields and basins. The only exceptions to this general rule are basins with significant coal-bed methane (CBM) wells, which often have low gas pressures and require more wellhead compression; although even in these CBM fields and basins the usage of wellhead compression is generally no more than 5% of total wells.

In addition to determining the fraction of wellhead compressors, it was necessary to determine the fraction of lateral compressors and whether these compressors should be counted in the area source emissions inventory for each state. Lateral compressors are also natural gas-fired compressors that serve to boost field pressures for delivery to transmission pipelines, but they typically serve multiple well-sites simultaneously. These compressors are therefore larger than wellhead compressors and may have sufficient annual emissions of NOx that they are counted in point source inventories (and thus are not considered area sources according to this analysis). Table 2-3 below lists the annual emissions thresholds of an individual source to be included in each state's point source inventory.

Table 2-3. Summary of state point source inventory thresholds (PTE = Potential to Emit).

State	Point Source Inventory Threshold
Alaska	PTE 100 TPY
Arizona	PTE 40 TPY
Colorado	2 TPY actual emissions
Montana	PTE 25 TPY
New Mexico	PTE 25 TPY
North Dakota	PTE 100 TPY
Nevada	PTE 5 TPY
Oregon	PTE 100 TPY
South Dakota	PTE 100 TPY
Utah	PTE 100 TPY
Wyoming	PTE 25 TPY

Based on Table 2-3 it was determined that lateral compressors would be included in all state point source inventories except for South and North Dakota and Utah. The lateral compressors in these states were accounted for in the Phase I work, and thus were not modified in this analysis. It should be noted that based on Table 2-3, it was determined that wellhead compressors in Colorado were counted in that state's point source inventory, since the inventory threshold was 2 tons per year actual emissions. In Alaska, wellhead compressor emissions were not estimated because all compressor sources are permitted by the state and thus included in the point source inventory.

The information provided by the O&G producers contacted in the data survey was used to determine the basin-wide and county-wide wellhead compressor emissions. The emissions estimates were conducted following Equation 2-3.

Equation 2-3:

$$E_{county,wellhead} = \%_{wellhead} \times N_{basin,county} \times \left(Activity \times Load_{wellhead} \times EF_{wellhead} \times DF_{wellhead} HP_{wellhead}\right)$$

where $E_{county,wellhead}$ is the county-wide emissions of a pollutant from wellhead compressors [tpy], $\%_{wellhead}$ is the fraction of wells in a basin that have a wellhead compressor at the well site [%], $N_{basin,county}$ is the number of wells in a basin that lie within a particular county's boundaries, *Activity* is the number of hours per year that wellhead compressors are operating [hr/yr], $Load_{wellhead}$ is the load on the wellhead compressor engines in each basin, $EF_{wellhead}$ is the emissions factor of a representative wellhead compressor engine in a basin [g/bhp-hr], $DF_{wellhead}$ is the deterioration factor of the representative wellhead compressor engine in a basin, and $HP_{wellhead}$ is the average horsepower of a representative wellhead compressor in each basin [hp]. *Activity* was assumed to be 24 hours per day, 365 days per year, or 8760 hours per year. This is a conservative assumption, but is a permitting requirement for estimating emissions in several states. Due to the lack of detailed information from producers on actual operating hours per year and any down-time of compressors, it is recommended that the operating hours and load factors be reviewed in more detail in any future emissions inventory effort.

It should be noted that $N_{basin,county}$ was determined by intersecting the boundaries of the basin with those of the county. Where a county was located in multiple focus basins, or multiple basins that included a focus basin and a basin not considered, the fraction of the wells located in the focus basin was used to generate the emissions. The well locations were obtained from state OGC databases of all wells in the state. The activity for all compressors was assumed to be 24 hours per day, 365 days per year, since information from producers indicated that no compressors were removed from operation for a significant length of time. More detailed producer data would be needed to quantify the exact amount of time that wellhead compressor engines are not in service in any particular basin, but this information was not obtained as part of the survey process. Similarly to drilling rigs, $EF_{wellhead}$ was determined from manufacturers rated emissions factors provided by the O&G producers but was also multiplied by the appropriate deterioration factor. Based on conversations with the O&G producers it was determined that wellhead compressors are often used in the field for decades, and thus were assumed to be fully deteriorated. The EPA's NONROAD2005 model was used to determine the deterioration factors, where it was assumed that all wellhead compressors were natural gas-fired spark-ignited compressor engines (EPA, 2005a). Table 2-4 below shows the deterioration factors for compressor engines.

Table 2-4. Deterioration factors for compressor engines from EPA's NONROAD2005 model.

Pollutant	Deterioration Factor
NOx	1.03
VOC	1.26
CO	1.35
PM	1.26

In basins for which more than one representative wellhead compressor engine make and model were provided, well counts in the basin were evenly divided among the compressor engine models. The fractions of wells in a basin that were equipped with wellhead compressors are summarized in Table 2-5 for each of the focus basins considered in this analysis.

Table 2-5. Fraction of wells with wellhead compressors in each basin of focused interest.

Basin	Wellhead Fraction
Southwestern Wyoming (Green River) Basin	0.4%
Wind River Basin	0.4%
Big Horn Basin	0.7%
Powder River Basin	4.5%
Uinta-Piceance Basin (UT)	5.0%
Paradox Basin	5.0%
San Juan Basin (South)[a]	20.4%
Permian Basin	2.2%

a – San Juan Basin (North) in Colorado was not included because Colorado wellhead compressors are included in the Colorado state point source inventory

Similarly to drilling rigs, the county-level wellhead compressor emissions estimates for 2002 were summed for all the counties in a state to generate state-level emissions estimates from wellhead compressors. It should be noted that for basins which were not in the focus list, the wellhead compression emissions were unchanged from the Phase I work, and thus were still based on gas production. Thus some state emissions totals represent emissions calculated using both the updated methodology and the previous Phase I methodology. Table 2-6 below shows the total estimated emissions from wellhead compressors in each state in the WRAP region.

Table 2-6. Estimated 2002 wellhead compressor engine emissions by state in the WRAP region.

State	Compressor Emissions (tpy)	
	NOx	SOx
Alaska[a]		
Arizona	8	0
Colorado[b]		
Montana	1,791	0

State	Compressor Emissions (tpy)	
	NOx	SOx
Nevada	33	0
New Mexico	35,140	1
North Dakota	2,920	0
Oregon	73	0
South Dakota	284	0
Utah	843	0
Wyoming	1,791	0
WRAP Total	46,154	1

a – Wellhead compressors in Alaska are permitted as part of a central station and counted in the state point source inventory
b – Colorado's point source inventory threshold is 2 tpy NOx, which includes all wellhead compressors, therefore the only compressor emissions listed here for Colorado are those from the Southern Ute tribal lands.

As can be seen in Table 2-6, by far the largest emissions of NOx from wellhead compressors are in New Mexico, and this is largely due to the high fractional use of wellhead compressors in the San Juan Basin. Note that North Dakota, South Dakota, Nevada and Oregon emissions were not updated from Phase I. Montana compressor emissions represent only a partial update, since only those counties within the Big Horn Basin and Powder River Basin were updated in Montana. The only source of SOx emissions from compressors is from New Mexico, where specific information was available from major O&G producers on H_2S levels in the gas. We did not have the resources to investigate whether there may be other basins with significant H_2S content in the gas produced, and hence in the compressor emissions.

NMED Inventory

The NMED ozone precursors study contains a complete EI analysis conducted for San Juan and Rio Arriba counties in New Mexico in 2002, and constitutes a complete set of data that supersede any other estimate for emissions in these counties (Pollack, A.; Russell, J.; Grant, J.; Friesen, R.; Fields, P.; Wolf, M. 2006). The focused inventory developed by ENVIRON for NMED covered only those O&G area sources located within San Juan and Rio Arriba counties in New Mexico for calendar year 2002. The methodology used was similar to the analysis conducted here, and relied on a survey of major producers in these counties to derive a count-based inventory of O&G equipment from which an emissions inventory could be conducted. Because the geographic region of interest was smaller than the WRAP region considered here, greater resources could be utilized to develop a detailed and accurate EI for these two counties. Thus all emissions estimates made in this work were used to replace any emissions previously estimated for these two counties. There were several equipment types that were identified to be in use in this study which had not been previously considered. Two such equipment types were salt water disposal (SWD) engines, and artificial lift engines. These two source categories were added to the 2002 EI, although their emissions are limited to these two counties in New Mexico.

The NMED ozone precursors study estimates for oil and gas area source emissions in 2002 in San Juan and Rio Arriba counties are compared to these estimates from the WRAP Phase I work in Tables 2-7 and 2-8 below.

Table 2-7. Emissions totals (tpy) for various oil and gas area source categories for San Juan and Rio Arriba counties from the NMED ozone precursors study.

	NOx		SOx		VOC	
Category	**Rio Arriba**	**San Juan**	**Rio Arriba**	**San Juan**	**Rio Arriba**	**San Juan**
Compressor Engines	11,279	16,042	0	1	1,079	1,981
Drill Rig Emissions	497	697	28	37	12	17
Artificial Lift emissions	166	298	0	0	3	6
SWD Engines	62	43	0	0	4	2
Gas Wells	2,412	3,790	2	3	47,415	57,570
Oil Wells	63	146	0	0	381	601

Table 2-8. Emissions totals (tpy) for various oil and gas area source categories for San Juan and Rio Arriba counties from the WRAP Phase I emissions inventory.

	NOx		SOx		VOC	
Category	**Rio Arriba**	**San Juan**	**Rio Arriba**	**San Juan**	**Rio Arriba**	**San Juan**
Compressor Engines	9,136	14,907				
Drill Rig Emissions	1,331	1,671	289	363		
CBM Emissions	48	94				
Gas Wells	2,406	3,039			19,925	33,154
Oil Wells	1	1			186	145

As can be seen from the comparison of Tables 2-7 and 2-8, the more detailed NMED study resulted in different estimates for NOx, SOx and VOC than the WRAP Phase I. Compressor engine NOx emissions increased in the NMED study because a more accurate count of compressor engines was possible for these two counties, however drilling rig NOx emissions decreased due to a better estimate of actual drilling time. VOC emissions increased significantly, by approximately 51,000 tpy (a 98% increase) due mainly to an improved estimate of gas well venting processes, and fugitive emissions from gas wells.

Southern Ute Tribal Inventory

The Southern Ute Indian Tribe emission inventory was developed in order to meet certain federal Environmental Protection Agency (EPA) reporting requirements and to meet internal tribal inventory requirements (Lee, C., 2005). The Southern Ute Indian Tribal Reservation occupies land in Archuleta and La Plata counties in Colorado. The inventory considered all major area source O&G emissions categories except drilling activities on the Southern Ute lands. This included wellhead compression, CBM pump engines, and other wellhead activities and included estimates of NOx, VOC, CO and PM emissions (Lee, C., 2005). In order to integrate this inventory with the updated 2002 EI, the emissions associated with wells located in the Southern Ute land were removed from the 2002 EI, and the Southern Ute EI estimates were added to replace them. In order to do this, the boundaries of the Southern Ute land were intersected with the two counties in Colorado, and the fraction of wells in each county that lie inside and outside the Southern Ute land were determined. These fractions were used to scale down emissions from the 2002 EI in each source category estimated by the Southern Ute Inventory in order to remove these emissions from the 2002 EI. Once emissions from the 2002 EI were removed, the Southern Ute Inventory estimates were added for each source category. It should be noted that drilling rig emissions for these two counties were not replaced in the 2002 EI, because they were not estimated by the Southern Ute Inventory. Rather it was verified that the Phase II estimates of drilling rig emissions would apply to all wells in Colorado, both on tribal and nontribal land.

Updated 2002 Emissions Inventory

The final emissions for 2002 in this current analysis were estimated by compiling the updated emissions for compressors and drilling rigs in the focus basins, by integrating the NMED ozone precursors study emissions for San Juan and Rio Arriba counties in New Mexico, by integrating the Southern Ute Tribal inventory, and finally by integrating the original Phase I inventory for all sources that were not updated. The results of the 2002 updated EI for the WRAP region is shown below in Table 2-9 for NOx emissions and Table 2-10 for SOx emissions. This table also includes, for comparison, the oil and gas point sources for each state from the current WRAP emissions inventory, and the total of oil and gas area and point sources.

Table 2-9. Updated 2002 EI showing NOx emissions (tpy) for all states.

States	Drill Rigs	Oil Well - All Sources	Compressor Engines	Gas Well - All Sources	CBM Pump Engines	All Area Sources	All Point Sources	TOTAL
Alaska[a]	877	0		9		886	45,431	46,317
Arizona		0	8	9		17	642	659
California						8,070	10,809	18,879
Colorado[b]	2,803	9	3,271	15,946	1,489	23,518	25,219	48,737
Idaho							2,590	2,590
Montana	1,046	42	1,791	4,678		7,557	3,996	11,553
Nevada	24	1	33	4		62	83	145
New Mexico	5,476	329	35,140	14,602	92	55,640	56,900	112,540
North Dakota	1,536	75	2,920	101		4,631	4,638	9,269
Oregon		0	73	12		85	1,182	1,267
South Dakota	29	3	284	44		361	323	684
Utah	334	31	843	2,127		3,335	3,049	6,384
Washington							480	480
Wyoming	4,997	111	1,791	6,398	1,428	14,725	13,423	28,148
WRAP Total	17,123	603	46,154	43,929	3,008	118,887	168,765	287,652

a – Wellhead compressors in Alaska are permitted as part of a central station and counted in the state point source inventory
b – Colorado's point source inventory threshold is 2 tpy NOx, which includes all wellhead compressors, therefore the only compressor emissions listed here for Colorado are those from the Southern Ute tribal lands.

Table 2-10. Updated 2002 EI showing SOx emissions (tpy) for all states.

States	Drill Rigs	Oil Well - All Sources	Compressor Engines	Gas Well - All Sources	CBM Pump Engines	All Area Sources	All Point Sources	TOTAL
Alaska[a]	66	0		0		66	773	839
Arizona		0	0	0		0	0	0
California						57	887	944
Colorado[b]	118	0	0	0	0	118	91	209
Idaho							7	7
Montana	225	0	0	0		225	11	236
Nevada	1	0	0	0		1	0	1
New Mexico	244	0	1	5	0	250	13,675	13,925
North	358	0	0	0		358	2,944	3,302

States	Drill Rigs	Oil Well - All Sources	Compressor Engines	Gas Well - All Sources	CBM Pump Engines	All Area Sources	All Point Sources	TOTAL
Dakota								
Oregon		0	0	0		0	8	8
South Dakota	6	0	0	0		6	10	16
Utah	17	0	0	0	0	17	0	17
Washington							8	8
Wyoming	150	0	0	0	0	150	12,188	12,338
WRAP Total	1,185	0	1	5	0	1,248	30,602	31,850

a – Wellhead compressors in Alaska are permitted as part of a central station and counted in the state point source inventory
b – Colorado's point source inventory threshold is 2 tpy NOx, which includes all wellhead compressors, therefore the only compressor emissions listed here for Colorado are those from the Southern Ute tribal lands.

Comparison of Phase I and Phase II 2002 Estimates

The oil and gas area source emissions estimates from the Phase II work are compared to the estimates of the Phase I work. Figure 2-2 below shows the comparison of 2002 NOx oil and gas area source emissions from these two analyses, and Figure 2-3 below shows the comparison of 2002 oil and gas area source SOx emissions from these two analyses. As can be seen from Figure 2-2, both Utah and Wyoming show a substantial percent reduction in NOx emissions from the Phase I and II analyses. This is largely due to a revised estimate of the fraction of wells using wellhead compression in these two states as discussed above. In addition, the well count-based emissions estimates for compressor engines removed the inaccurate Phase I assumption that all gas production would have an associated emissions factor for gas equipment source categories. Incidental gas production from a well producing mainly oil does not typically have gas equipment installed at the well site. It should be noted that for Colorado, the addition of wellhead compressor emissions on Southern Ute Tribal land represented the only wellhead compressor emissions for that state, since all other wellhead compressors fall within Colorado's point source inventory.

As can be seen from Figure 2-3, drilling rig emissions in Wyoming, Colorado, New Mexico and Utah were all updated in this current analysis because the focus basins are largely in these states. The revised estimates of drilling time are substantially lower than the times estimated in the Phase I analysis using spud and completion dates. This reflects the fact that completion activities often take a significant amount of time but the drilling rigs are not expected to be in operation during that time.

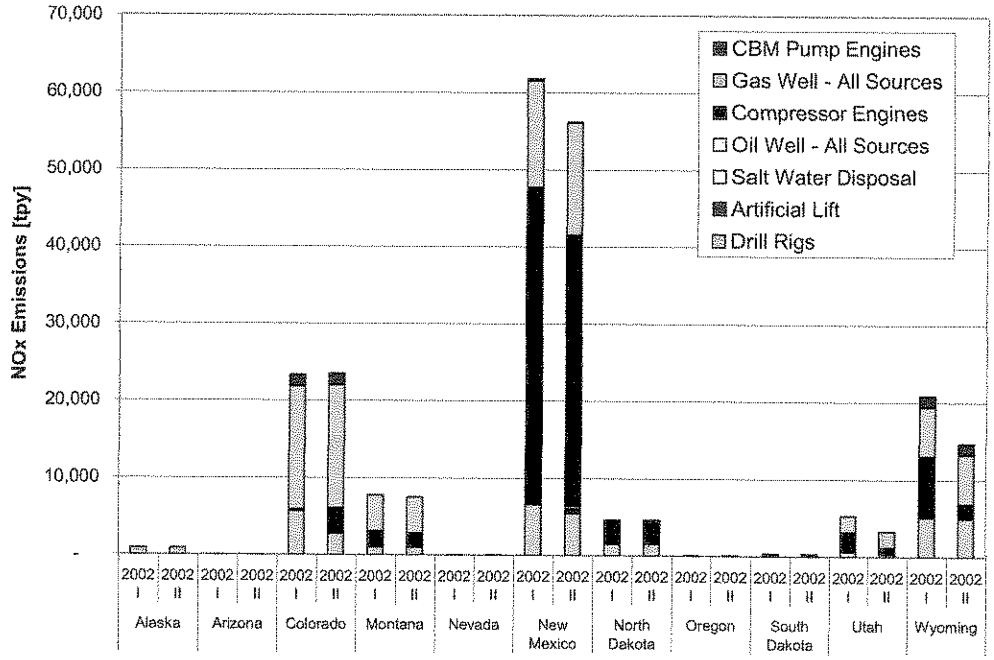


Figure 2-2. Comparison of 2002 state total oil and gas area source NOx emissions from Phase I and Phase II analyses.

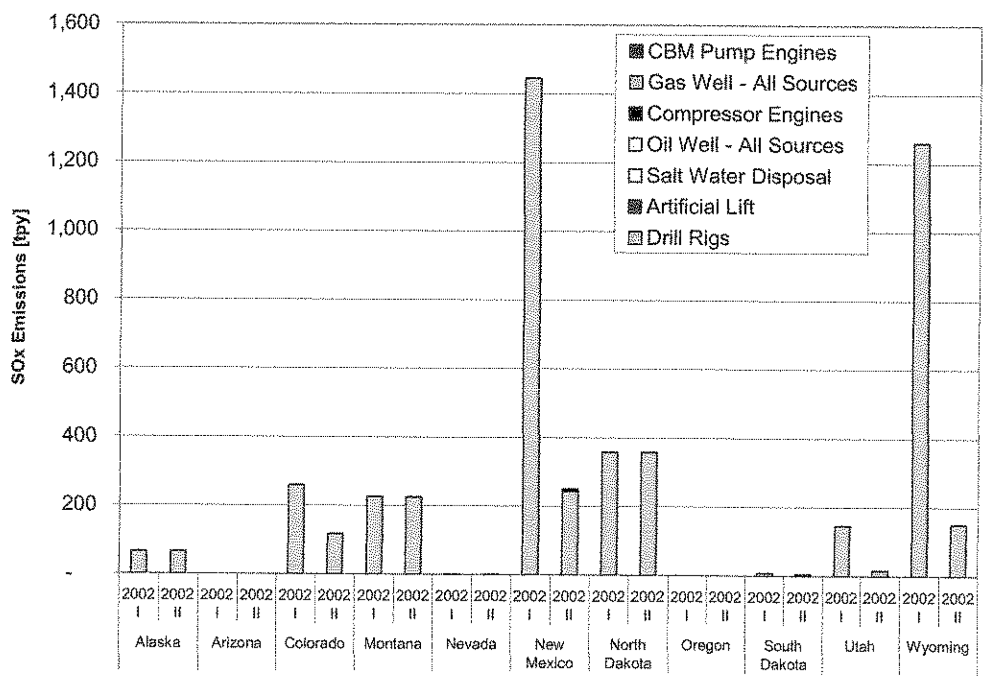


Figure 2-3. Comparison of 2002 state total oil and gas area source SOx emissions from Phase I and Phase II analyses.

3. UPDATING BASELINE EMISSIONS FROM 2002 to 2005

The second major task in this project was to update the baseline EI, from which projections to 2018 are made, from 2002 to 2005. This was considered a valuable addition to this analysis because any future projections would be able to incorporate the tremendous growth in O & G activity in the western United States that has occurred between 2002 and 2005. The number of drilling permits alone issued by the Federal Bureau of Land Management in the Rocky Mountain area has nearly doubled between 2002 and 2005 (Talhelm, J., 2006). 2005 would serve as an additional data point against which to calibrate estimated emissions projections to 2018, and to verify the accuracy of data sources that predict 2005 O&G activity. In addition, there have been increasing efforts by state environment departments and by the state OGCs to maintain more accurate records of O&G activity and to make those records publicly available (Madison, C., Schlichtemeier, C., 2007, Carlin, J., 2007). Thus using 2005 well-specific data for each state would make use of this improved database of information.

The update of the baseline EI from 2002 to 2005 involved utilizing and combining these two sources of information:

- State OGC well-specific databases
- State OGC databases of wells spudded (drilling records)

The state OGC databases contain lists of wells, the locations of the wells by latitude/longitude and by county, oil and gas production from each well (where applicable), and the well status which includes whether the well is still active and whether the well is a CBM well. The state OGC drilling records indicate the date that a well is spudded – indicating that drilling has begun – the date that the well was completed, and the location of the spud.

The methodology used in this task was to derive scaling factors on the basis of the state OGC databases for spuds and well location and production. These scaling factors were estimated on a county-level basis for each state, and applied to the 2002 EI discussed in Section 3 of this report to generate a new 2005 EI.

Scaling Based on State OGC Databases

Several scaling factors were derived for scaling 2002 to 2005 emissions by source category and by county for the WRAP region. Scaling factors were derived separately for drilling, count-based compressor emissions, count-based other wellhead emissions, gas-production-based emissions, and oil-production-based emissions. Each type of scaling factor is described below.

Drilling scaling factors were determined by looking at drilling records maintained by state OGCs. These records give an indication of the number of wells spudded in each county for 2005. Spudding indicates the beginning of drilling at that well site. It was assumed that all wells spudded in 2005 would be completed by 2005 and were thus considered a single drilling event. All 2002 county-level emissions generated in the previous task were scaled by the ratio of 2005 number of wells spudded in that county to 2002 number of wells spudded in that county. Two special cases of drilling scaling factors were considered. If no new wells were drilled in 2005 in counties for which there was active drilling in 2002, the drilling emissions scaling factor was assumed to be zero for that county. In counties where no drilling occurred in 2002 but drilling did occur in 2005, a different method was employed to generate a scaling factor. The 2002 state average emissions per well was determined from the 2002 EI update conducted in the previous task, and then this emissions per well was multiplied by the number of wells drilled in that county in 2005.

Count-based scaling factors were used to scale emissions categories that were updated in this analysis on the basis of count, and those emissions categories that were estimated on a count basis but not updated from the previous Phase I work. If counties were only partially in a focus basin that was updated in this analysis, the fraction of the total well count in that county intersecting the basin boundaries was used to scale the emissions correspondingly. Frequently the state OGC databases do not indicate whether a well is an oil well or a gas well. This is important because this analysis makes the assumption that oil wells do not have gas-producing equipment at the well site and vice versa. Many wells produce both oil and gas, and the ratio of the annual production of gas to oil, known as the gas-oil ratio (GOR), was used to determine whether a well is an oil or gas well. If the oil production or gas production was zero, the well could easily be labeled an oil or gas well. Where both gas and oil production exists, the count of wells by GOR was plotted to determine a reasonable cut-off GOR below which the well would be classified as an oil well. An example plot is shown here for New Mexico in Figure 3-1. The GOR distribution was seen to be roughly bimodal with a cut-off GOR of 0.1, below which wells were considered to be oil wells and above which wells were considered to be gas wells. For all emissions source categories that were scaled on a count basis, the 2005 emissions were generated by multiplying the 2002 emissions of that source category by the ratio of the 2005 well count to the 2002 well count.

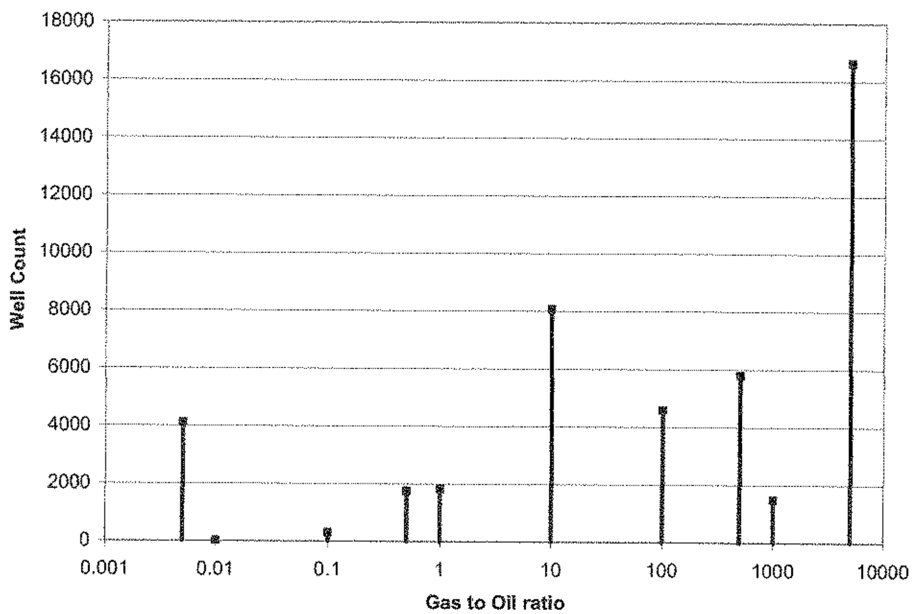


Figure 3-1. New Mexico GOR as a function of well count for 2005.

Production based scaling factors were derived for both oil-based and gas-based emissions source categories in a manner similar to the count-based approach described above. This was necessary for all source categories that were not updated from the previous Phase I inventory.

The scaling factors were applied to the 2002 EI in order to generate 2005 emissions. Tables 3-1 and 4-2 show the updated NOx and SOx emissions respectively from drilling rigs and wellhead compressor engines for 2002 and 2005 for all states.

Table 3-1. NOx emissions from drilling rigs and wellhead compressor engines in 2002 and 2005, and change (in tons) and percentage change in NOx emissions from 2002 to 2005.

State	Drill Rig Emissions				Compressor Emissions			
	NOx [tpy]		Change 2002 to 2005 [tpy]	% Change 2002 to 2005	NOx [tpy]		Change 2002 to 2005 [tpy]	% Change 2002 to 2005
	2002	2005			2002	2005		
Alaska	877	835	-42	-5%				
Arizona	0	0	0	0%	8	6	-2	-25%
Colorado[a]	2,803	8,000	+5,197	+185%	3,271	3,302	+31	+1%
Montana	1,046	3,007	+1,961	+187%	1,791	2,267	+476	+27%
Nevada	24	37	+13	+54%	33	33	0	0%
New Mexico	5,476	8,640	+3,164	+58%	35,140	35,345	+205	+1%
North Dakota	1,536	3,055	+1,519	+99%	2,920	2,799	-121	-4%
Oregon	0	0	0		73	51	-22	-30%
South Dakota	29	203	+174	+600%	284	305	+21	+7%
Utah	334	2,888	+2,554	+765%	843	996	+153	+18%
Wyoming	4,997	15,783	+10,786	+216%	1,791	3,288	+1,497	+84%
WRAP Total	**17,123**	**42,448**			**46,154**	**48,393**		

a – Wellhead compressor emissions in Colorado are only those located on Southern Ute Tribal land; all other wellhead compressors are assumed to be part of Colorado's point source inventory and thus are not listed here.

Table 3-2. SOx emissions from drilling rigs and wellhead compressor engines in 2002 and 2005, and change (in tons) and percentage change in SOx emissions from 2002 to 2005.

State	Drill Rig Emissions				Compressor Emissions			
	SOx [tpy]		Change 2002 to 2005 [tpy]	% Change 2002 to 2005	SOx [tpy]		Change 2002 to 2005 [tpy]	% Change 2002 to 2005
	2002	2005			2002	2005		
Alaska	66	62	-4	-6%				
Arizona	0	0	0		0	0	0	0%
Colorado[a]	118	350	+232	+197%	0	0	0	0%
Montana	225	640	+415	+184%	0	0	0	0%
Nevada	1	1	0	0%	0	0	0	0%
New Mexico	244	362	+118	+48%	1	1	0	0%
North Dakota	358	688	+330	+92%	0	0	0	0%
Oregon	0	0	0		0	0	0	0%
South Dakota	6	43	+37	+617%	0	0	0	0%
Utah	17	149	+132	+776%	0	0	0	0%
Wyoming	150	541	+391	+260%	0	0	0	0%
WRAP Total	**1,185**	**2,835**			**1**	**1**		

a – Wellhead compressor emissions in Colorado are only those located on Southern Ute Tribal land; all other wellhead compressors are assumed to be part of Colorado's point source inventory and thus are not listed here.

Table 3-1 shows that NOx emissions from drilling rigs increased dramatically in Wyoming, North Dakota, Montana and Colorado, in terms of total tonnage of NOx emissions. This reflects the increased exploration activity occurring in these states between 2002 and 2005. It should be noted that what is presented in tables 3-1 and 3-2 above are state total emissions, and thus it is not possible from this information to determine which basin's activities contributed to this state total. Wellhead compressor NOx emissions are not seen to increase significantly in most of these states from 2002 to 2005, and have decreased in some states as wells are plugged and abandoned and no new producing wells have been added. Wellhead compressors are only used on a relatively small fraction of new wells in most of these states, thus even a large growth in number of wells in these three years would not produce a major growth in emissions. In addition, during the initial years of life of a new producing gas well, wellhead compression is often not needed to boost pressure for transmission. In the San Juan Basin in New Mexico, which has a high usage of wellhead compressors, there was not a significant growth in the number of new producing wells developed between 2002 and 2005. However, in Wyoming the rapid growth in development of the Powder River Basin, where approximately 5% of wells have wellhead compressors, leads to a near doubling of emissions from wellhead compressors. It should be noted that Colorado's wellhead compressor emissions are only derived from the Southern Ute Tribal Inventory. All other wellhead compressors are already captured by Colorado's point source inventory and thus not included here.

4. CONTROL STRATEGY EVALUATION

Under this task, potential control technologies were evaluated, that can be applied to the sources of NOx, PM, SOx and VOC as listed in Table 4-1.

Table 4-1. Control technology evaluations conducted.

Equipment	NOx	PM	SOx	VOC
Drill Rigs	X	X	X	
Compressor Engines	X	X		
Tanks				X
Glycol Dehydration Units				X
Pneumatic Devices				X
Completion-Flaring and Venting				X

For each of the sources identified in Table 4-1, a range of viable control options were evaluated. Included in these options were

- Engine modifications (e.g., lean-burn engines, ignition timing, exhaust gas recirculation)
- After treatment control devices (e.g., catalysts, diesel particulate filters)
- Engine replacement/repowering
- Various methods for reducing VOCs from exploration and production activities

The information developed under this task is provided in a series of White Papers that are contained at the end of this chapter. It should be noted again that the focus of this study was smaller area sources of emissions from oil and gas operations that are not currently included in the point source emission inventories for each of the states in the WRAP region. Therefore, most if not all equipment evaluated is equipment found at the well head and possibly from smaller lateral compressor operations.

For each control option, the control technology and the application of each technology to types of equipment identified in Table 4-1 were described. The range of control efficiencies, the potential emissions reductions, and the range of costs and cost-effectiveness and the potential for applying the controls to existing equipment (i.e., retrofit applications) and new equipment was determined for each application. The potential emissions reductions were determined by applying the control efficiencies to representative equipment identified in each basin and described earlier in this report. The cost-effectiveness was determined using the methodology adopted by the California Air Resources Board (CARB) in its evaluation of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines (CARB, 2001a), which is described in detail below. The cost-effectiveness was determined by dividing the annualized cost by the ton of pollutants reduced from representative equipment found for these operations. While the White Papers were developed for controlling various exploration and production activities, resources did not allow the determination of potential emissions reductions. Therefore, the cost of control equipment was determined for these sources but the cost-effectiveness was determined only for drill rigs and compressor engines. It should be noted that the costs used for this report were not indexed to 2007 dollars.

It should be emphasized that there are multiple variables to be considered in calculating the cost and operational needs of individual control technologies. Many technologies require testing and evaluation in the settings where they have previously not been applied. At the same time, these technologies have been tested and are in use in other oil and gas fields. This report presents estimates of the effectiveness of these technologies as they have been tested and applied to date. These control technologies would very likely receive additional analyses before being adopted into a regulation or permit by a regulatory agency.

COMPRESSOR ENGINES

The combustion of fuels in oil and gas compression operations results in emissions of NOx, CO, VOC, fine particulate matter (PM_{10}) and sulfur oxides (SOx). Because most oil and gas compressor engines operate on natural gas, the primary pollutant of concern is NOx. While the effort for this study was focused on visibility pollutants, the reductions of particulate matter were not evaluated because emissions are minimal due to the use of natural gas as a fuel. Because PM emissions from natural gas-fired compressors are expected to be very small, information on PM emissions factors was not easily available. Sulfur dioxide emission reductions were not evaluated because information obtained from compressor operators indicated that only low sulfur content natural gas is used in compressor engines (Smith, G.R., BP America Inc., 2007, Stewart, D., Encana Corp., 2007). Therefore, the NOx reduction potential and the cost-effectiveness were estimated for a range of well head compressor engines across the WRAP region. Based on this study, the majority of wellhead compressor engines ranged in size from 50 hp – 300 hp. In some basins, operators reported wellhead compressors in excess of 300 hp.

Most compressor engines at the well head are spark ignition (SI) internal combustion engines. SI engines typically are fueled with natural gas or volatile liquid fuels, such as gasoline. Because SI engines fired on natural gas are the primary source of compressor engine emissions in oil and gas operations, we focused on these engines for the purpose of evaluating potential control technologies or strategies. SI engines can operate under fuel-lean conditions or under stoichiometric to slightly fuel-rich conditions. Stoichiometric condition is defined as the condition when there is exactly enough free oxygen to combine with all of the fuel. Under this condition the mass ratio of air to fuel is considered a stoichiometric mixture. Most large SI engines (over about 1000 hp) are fuel-lean type engines while smaller engines (300 hp and less) are generally rich-burn stationary engines and are the primary source of emissions at natural gas production facilities.

Controls for compressor engines can be grouped into the following general categories: combustion modifications (or primary methods); fuel switching; post-combustion controls (or secondary methods); and replacement of the engine with a new, low emissions engine or electric motor. Combustion modifications can reduce NOx formation by changing the air/fuel mixture, reducing peak temperatures, or shortening the residence time at high temperatures. Emissions of CO and VOC are generally the result of incomplete combustion. They can be controlled by combustion modifications that increase oxygen, temperature, residence time at high temperatures and the mixing of air and fuel. It should be noted that some of these tend to increase NOx so care must be taken to assure that reductions in one pollutant do not increase the emissions of another pollutant. Where appropriate, the discussions in the White Papers that follow identify the impact of controlling NOx on the other pollutants. A summary of the compressor engine control technologies, control efficiency, NOx reductions and cost-effectiveness is shown Table 4-2.

Table 4-2. Summary of control technologies for compressor engines.

Measure No.	Control Measure Name[1]	Control Efficiency %	NOx Reduction (tpy)	Cost-Effectiveness ($/ton)
CE-1	NSCR	90 to 98	1.0 to 45.3	200 to 7,900
CE-2	AFR	10 to 40	0.3 to 12.1	100 to 2,500
CE-3	ITR	15 to 30	0.3 to 10.8	100 to 1,200
CE-4	AFR + ITR	10 to 40	0.3 to 12.1	100 to 3,600
CE-5	PSC	80	0.9 to 38.5	100 to 3,000
CE-6	L-E	80	0.9 to 38.5	100 to 2,600
CE-7	SCR	80	0.9 to 38.5	900 to 31,000
CE-8	Replace Engine[2]	60 to 100	0.9 to 38.5	100 to 4,700

1 NSCR - Non-selective catalytic reduction AFR - Air Fuel Ratio Control, ITR - Ignition Timing Retard, PSC - Prestratified Charge, L-E - Low Emission Engine, SCR - Selective Catalytic Reduction, EGR - Exhaust Gas Recirculation, CEC - Crankcase Emission Control, DPF - Diesel Particulate Filter, DOC - Diesel Oxidation Catalyst, LNC - Lean NOx Catalyst, NG - Natural Gas, VRU – Vapor Recovery Unit
2 Replace Engine with electrified engine does not include any potential impact from increases in central station power plants due to increased electrical load.

DRILL RIG ENGINES

Drilling for natural gas involves the use of drilling rigs that generally employ diesel fired engines as the power source. The type of drilling that occurs is known as rotary drilling, and consists of a sharp, rotating metal bit used to drill through the Earth's crust. This type of drilling is used primarily for deeper wells that that have high downhole pressures. Most rotary rigs require 1,000 to 3,000 hp, and when drilling in excess of 20,000 feet below the surface may require even more hp. The energy from these diesel engines is used to power the rotary equipment, the hoisting equipment, and the circulating equipment as well as incidental lighting, water, and compression requirements not associated directly with drilling. Hoisting equipment consists of tools used to raise and lower whatever other equipment may be used in the well. The most visible part is the derrick that extends vertically from the well hole. The derrick serves to support drilling cables and pulleys to lower and raise equipment. Circulating equipment consists of drilling fluid which is circulated down through the well hole during the drilling process and subsequently pumped up and out to remove the rock and other material that is drilled through. In addition to diesel engines, other types of engines such as natural gas or gasoline powered engines are also used, however much less frequently.

In estimating emissions from diesel engines used for drilling operations, it is important to note that once the well has been drilled, well completion activities are performed to allow the well to become productive. It is also important to note that other compounds and gases such as oil and water may be present and must be removed before the natural gas is sent through the pipeline. Well completion activities involve strengthening the well hole with casing, evaluating the pressure and temperature of the formation, and then installing the proper equipment to ensure proper flow of natural gas out of the well. These activities are not considered in the controls analysis and White Papers presented below for drilling rigs.

Based on this study, we found that drilling rig engines varied widely in activity as well as size. If multiple engines are present on a single rig, control is applied to all engines and the overall "rig" cost-effectiveness and NOx reduction potential reported. Individual drilling rig engine sizes in the regions studied varied from 200 hp – 1500 hp. Cost-effectiveness and NOx reduction potential is estimated for a range of drilling rigs found in this study across the WRAP region. A summary of the drilling rig engine control technologies, control efficiencies, NOx reductions and cost-effectiveness is shown in Table 4-3

Table 4-3. Summary of control technologies for drilling rigs.

Measure No.	Control Measure Name[1]	Control Efficiency %	NOx Reduction (tpy)	Cost-Effectiveness ($/ton)
DRE-1	ITR	15 to 30	6.6 to 17.2	1,000 to 2,200
DRE-2	SCR	80 to 95	25.8 to 66.8	3,000 to 7,700
DRE-3	EGR	40	11.8 to 30.6	800 to 2,000
DRE-7	LNC	10 to 20	4.4 to 11.5	1,400 to 3,400
DRE-8	Low S Diesel	14	TBD	TBD
DRE-8	NG	85 to 91	TBD	TBD
DRE-8	Emulsified Diesel	20	5.9 to 15.3	4,500 to 11,600
DRE-9	Tier 2 to Tier 4 Replacement	43 to 93	7.8 to 33.6	900 to 2,400
DRE-9	Tier 3 to Tier 4 Replacement	43 to 89	4.7 to 20.1	900 to 2,000

1 NSCR - Non-selective catalytic reduction AFR - Air Fuel Ratio Control, ITR - Ignition Timing Retard, PSC - Prestratified Charge, L-E - Low Emission Engine, SCR - Selective Catalytic Reduction, EGR - Exhaust Gas Recirculation, CEC - Crankcase Emission Control, DPF - Diesel Particulate Filter, DOC - Diesel Oxidation Catalyst, LNC - Lean NOx Catalyst, NG - Natural Gas, VRU – Vapor Recovery Unit

EXPLORATION AND PRODUCTION

Several measures for reducing emissions of volatile organic compounds at well head operations were identified. Many of these measures have been identified under the U. S. Environmental Protections Agency's (EPA) Natural Gas STAR Program, which is a flexible, voluntary partnership between EPA and the oil and natural gas industry. Through the Program, EPA works with companies that produce, process, and transmit and distribute natural gas to identify and promote the implementation of cost-effective technologies and practices to reduce emissions of methane, a potential greenhouse gas, and volatile organic compounds. Gas STAR promotes the use of these emission reduction technologies and practices through the program's Best Management Practices (BMPs) and other Technologies and Practices. Table 4-4 identifies several of these measures.

Table 4-4. Control measures for exploration and production activities.

Measure No.	Category	Control Measure Name	Pollutant	Control Efficiency (%)
EAP-1	Glycol Dehydration	Optimize Circulation	VOC	33 to 67
		Electric Pump	VOC	67
		Flash Tank	VOC	10 to 40
		Desiccant	VOC	99
EAP-2	Pneumatic Controls	Instrument Air	VOC	98
		Non-Bleed	VOC	98
EAP-3	Completion Venting and Flaring	Flaring	VOC	62 to 84
		Green Completion	VOC	70
EAP-4	Tanks	VRU	VOC	95
		Water Blanket	VOC	TBD

As described earlier, emissions reductions were not determined for these sources due to lack of resources. Recommendations for further work that would further quantify emissions from these operations are discussed later in this report.

METHODOLOGY FOR CONTROL TECHNOLOGY EVALUATION

To describe the methodology used to evaluate control technologies, we provide an example calculation of the cost-effectiveness for a drilling rig in Table 4-5.

Table 4-5. Example calculation of cost-effectiveness for drilling rig engine.

	CATERPILLAR D398	
	Baseline	**SCR**
Operating Fraction (%/yr)	0.75	0.75
Annual usage (hr/yr)	6,570	6,570
Annualized Capital Cost		$142,645
Useful Life (years)	10.0	10.0
NOx Emission Factor (g/bhp-hr)	8.94	1.12
VOC Emission Factor (g/bhp-hr)	0.11	0.11
Engine Size (bhp)	967	967
Avg. Load	0.68	0.68
NOx g/hr	5879	735
VOC g/hr	72	72
NOx tons/year	42.57	5.32
VOC tons/year	0.52	0.52
NOx Reduction tons/year		37.25
VOC Reduction tons/year		0.00
Annualized Cost-Effectiveness (NOx Only)		$3,829
Annualized Cost-Effectiveness (VOC Only)		N/A

From Table 4-5, we first determined the fraction of the year that the drilling rig was in operation, which in turn provided the annual usage for each representative engine. This fraction varied for each geographical area based on information provided by the producers. The annualized cost was then determined for each representative engine and averaged for each basin to estimate the annual costs for each control measure. The annualized cash flow method was used to determine annual cost. This method was applied to the pre-tax capital and installation costs using a nominal interest rate (including inflation) of 10 percent over a ten year life. In most cases, fuel costs were not included. The annual operation and maintenance costs attributable to the control method were added to the annualized cost. Where appropriate, the additional annual fuel cost was added. Costs for compliance including reporting and recordkeeping, permit applications and emissions testing were not included. Using emission factors described in earlier chapters, the total emissions were determined on an annual basis. Applying the control effectiveness for each control technology to the annual emissions, we were then able to calculate the annualized const-effectiveness as shown in Table 4-5

WHITE PAPERS

The following pages contain the White Papers for each control measure. It should be noted that the range of cost-effectiveness identified for each control measure represents the range for the size of equipment found in the areas studied and not necessarily for the entire range of equipment sizes identified in the cost tables.

Table 4-6. Summary of control options.

Measure No.	Category	Control Measure Name[1]	Pollutant	Control Efficiency %
CE-1	Compressor Engines-Rich Burn	NSCR	NOx	90 to 98
			CO	80
			HC	50
CE-2	Compressor Engines, SI and CI	AFR	NOx	10 to 40
CE-3	Compressor Engines, SI and CI	ITR	NOx	15 to 30
CE-4	Compressor Engines, SI and CI	AFR + ITR	NOx	10 to 40
CE-5	Compressor Engines, Rich Burn	PSC	NOx	80
CE-6	Compressor Engines, SI	L-E	NOx	80
CE-7	Compressor Engines, Lean Burn	SCR	NOx	80
CE-8	Compressor Engines, All	Replace Engine	NOx	60 to 100
DRE-1	Drilling Rig Engines	ITR	NOx	15 to 30
DRE-2	Drilling Rig Engines	SCR	NOx	80 to 95
DRE-3	Drilling Rig Engines	EGR	NOx	40
DRE-4	Drilling Rig Engines	CEC	PM	6 to 23
DRE-5	Drilling Rig Engines	DPF	PM	85
			CO	90
			HC	90
DRE-6	Drilling Rig Engines	DOC	PM	25
			CO	85
			HC	90
DRE-7	Drilling Rig Engines	LNC	NOx	10 to 20
DRE-8	Drilling Rig Engines	Low S	PM	14
		NG	NOx	85 to 90
			PM	50 to 80
		Emulsion	NOx	20
			PM	17
			CO	13
EAP-1	Glycol Dehydration	Optimize Circulation	VOC	33 to 67
		Electric Pump	VOC	67
		Flash Tank	VOC	10 to 40
EAP-2	Pneumatic Controls	Instrument Air	VOC	98

Measure No.	Category	Control Measure Name[1]	Pollutant	Control Efficiency %
		Non-Bleed	VOC	98
EAP-3	Completion Venting and Flaring	Flaring	VOC	62 to 84
		Green Completion	VOC	70
EAP-4	Tanks	VRU	VOC	95
		Water Blanket	VOC	TBD

NSCR - Non-selectic catalytic reduction
AFR - Air Fuel Ratio Control
ITR - Ignition Timing Retard
PSC - Prestratified Charge
L-E - Low Emission Engine
SCR - Selective Catalytic Reduction
EGR - Exhaust Gas Recirculation
CEC - Crankcase Emission Control
DPF - Diesel Particulate Filter
DOC - Diesel Oxidation Catalyst
LNC - Lean NOx Catalyst
NG - Natural Gas

Table 4-7. Summary of emissions reductions and cost-effectiveness.

Measure No.	Category	Control Measure Name	Control Efficiency %	NOx Reduction[1] (tpy)	Cost-Effectiveness[2] ($/ton)
CE-1	Compressor Engines-Rich Burn	NSCR	90 to 98	1.0 to 45.3	200 to 7,900
CE-2	Compressor Engines, SI and CI	AFR	10 to 40	0.3 to 12.1	100 to 2,500
CE-3	Compressor Engines, SI and CI	ITR	15 to 30	0.3 to 10.8	40 to 1,200
CE-4	Compressor Engines, SI and CI	AFR + ITR	10 to 40	0.3 to 12.1	100 to 3,600
CE-5	Compressor Engines, Rich Burn	PSC	80	0.9 to 38.5	100 to 3,000
CE-6	Compressor Engines, SI	L-E	80	0.9 to 38.5	100 to 2,600
CE-7	Compressor Engines, Lean Burn	SCR	80	0.9 to 38.5	900 to 31,000
CE-8	Compressor Engines, All	Replace Engine	60 to 100	0.9 to 38.5	100 to 4,700
DRE-1	Drilling Rig Engines	ITR	15 to 30	6.6 to 17.2	1,000 to 2,200
DRE-2	Drilling Rig Engines	SCR	80 to 95	25.8 to 66.8	3,000 to 7,700
DRE-3	Drilling Rig Engines	EGR	40	11.8 to 30.6	800 to 2,000
DRE-7	Drilling Rig Engines	LNC	10 to 20	4.4 to 11.5	1,400 to 3,400
DRE-8	Drilling Rig Engines	Low S Diesel	14	TBD	TBD
DRE-8	Drilling Rig Engines	NG	85 to 91	TBD	TBD
DRE-8	Drilling Rig Engines	Emulsified Diesel	20	5.9 to 15.3	4,500 to 11,600
DRE-9	Drilling Rig Engines	*Tier 2 to Tier 4* Replacement	43 to 93	7.8 to 33.6	900 to 2,400
DRE-9	Drilling Rig Engines	Tier 3 to Tier 4 Replacement	43 to 89	4.7 to 20.1	900 to 2,000

1 For compressor engines and drilling rigs a range of NOx reductions is presented based on the range of engine sizes to which the control measure is applied. For drilling rigs there is also a wide variation in activity in different geographic regions.
2 For compressor engines and drilling rigs a range of cost-effectiveness values is presented based on the range of engine sizes to which the control measure is applied. For drilling rigs there is also a wide variation in activity in different geographic regions. If multiple engines are present on a single drilling rig, the measure is assumed to apply to all engines and the cost-effectiveness is estimated as the total cost of the measure for all engines on the rig, divided by the total potential NOx reductions.

CE-1 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines – Rich Burn

Control Measure Name: **Nonselective Catalytic Reduction (NSCR)**

Applicable Regulation: None for Engines less than 500 hp (Depends on State)

Application: This control measure applies to Rich-Burn engines > 50 hp

Pollutants: NOx, CO and HC

Control Efficiency: NOx: 90 to 98%, CO: 80%, HC: 50%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Capital and annual cost information was obtained from engine data gathered by Environ for the Northeast Texas Air Care pilot project. Cost information is summarized in the table below.

Table CE-1-1. Capital, O&M and annualized costs by engine horsepower. (CARB, 2001b)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	13,500	6,000	$8,197
151 - 300	18,500	6,000	$9,011
301 - 500	20,500	7,000	$10,336
501 - 1000	30,500	8,000	$12,964
1001 - 1700	46,500	10,000	$17,568

Cost Effectiveness: $199/ton-NOx – $7,911/ton-NOx

Status: Demonstrated

Control Measure Description: This control method is applicable to all rich-burn engines, and is probably the most popular control method for these types of engines. Manufacturers generally do not offer lean-burn engines in sizes less than 300 hp so this technology would only apply to rich burn engines less than 300 hp. NSCR is essentially the same catalytic reduction technique used in automobile applications and is also referred to as a three-way catalyst system because the catalyst reactor simultaneously reduces NO_x, CO, and HC to water (H_2O), carbon dioxide (CO_2), and diatomic nitrogen (N_2). The chemical stoichiometry requires that O_2 concentration levels be kept at or below approximately 0.5 percent, and most NSCR systems require that the engine be operated at fuel-rich A/F's. As a result, CO and HC emissions typically increase, the brake-specific fuel consumption (BSFC) also increases due to the fuel-rich operation and the increased backpressure on the engine from the catalyst reactor.

Sustained NOx reductions are achieved with changes in ambient conditions and operating loads only with an automatic A/F control system, and a suitable A/F controller is not available for fuel-injected engines. Work by Environ in Northeast Texas has demonstrated NOx emission reduction efficiencies of 85 to 98 percent (Friesen, R., Russell, J., Lindhjem, C., Yarwood, G., 2006), greater than 80% for CO and greater than 50% VOC (CARB, 2001b). In tests run on seven different engines (each less than 500 hp and fueled with natural gas), an NSCR system (three-way catalyst and AFR controller) was found to have the greatest potential for reducing NOx emissions from this type of compressor engine. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 0.3 to 1.6 g/hp-hr (20 to 110 ppmv). Numerous test reports support this NOx reduction efficiency range, but the corresponding CO emission levels range up to 37 g/hp-hr (4,500 ppmv) in some cases. Where controlled NO_x emission levels result in unacceptable CO emission rates, an oxidation catalyst may be required to reduce these emissions.

Other Impacts

The predominant catalyst material used in NSCR applications is a platinum-based metal catalyst. The spent catalyst material is not considered hazardous, and most catalyst vendors accept return of the material, often with a salvage value that can be credited toward purchase of replacement catalyst.

CE-2 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines

Control Measure Name: Air/Fuel Ratio Controllers (AFR)

Applicable Regulation:

Application: This control measure applies to Spark Ignition and Compression Ignition engines.

Pollutants: NOx

Control Efficiency: NOx: 10 to 40%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Capital and annual cost information was obtained from engine data gathered by Environ for the Northeast Texas Air Care pilot project. Cost information is summarized in the table below.

Table CE-2-1. Capital, O&M and annualized costs by engine horsepower. (Friesen, R., Russell, J., Lindhjem, C., Yarwood, G., 2006)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	4,200	N/A	$684
151 - 300	5,000	N/A	$814
301 - 500	5,000	N/A	$814
501 - 1000	5,300	N/A	$863
1001 - 1700	5,300	N/A	$863

Cost Effectiveness: $68/ton-NOx – $2,482/ton-NOx

Status: Demonstrated

Control Measure Description: This method has been used extensively on a wide variety of engines including SI and CI engines. Adjusting the A/F toward fuel-rich operation reduces the oxygen available to combine with nitrogen, thereby inhibiting NO_x formation. Figure CE2.1 shows the relationship between NOx formation to CO and VOCs. Stiochioimetry is achieved when the air/fuel ratio is such that all the fuel can be fully oxidized with no residual oxygen remaining. NOx formation is highest when the air/fuel ratio is slightly on the lean side of stiochiometric. At this point both CO and VOC are relatively low.

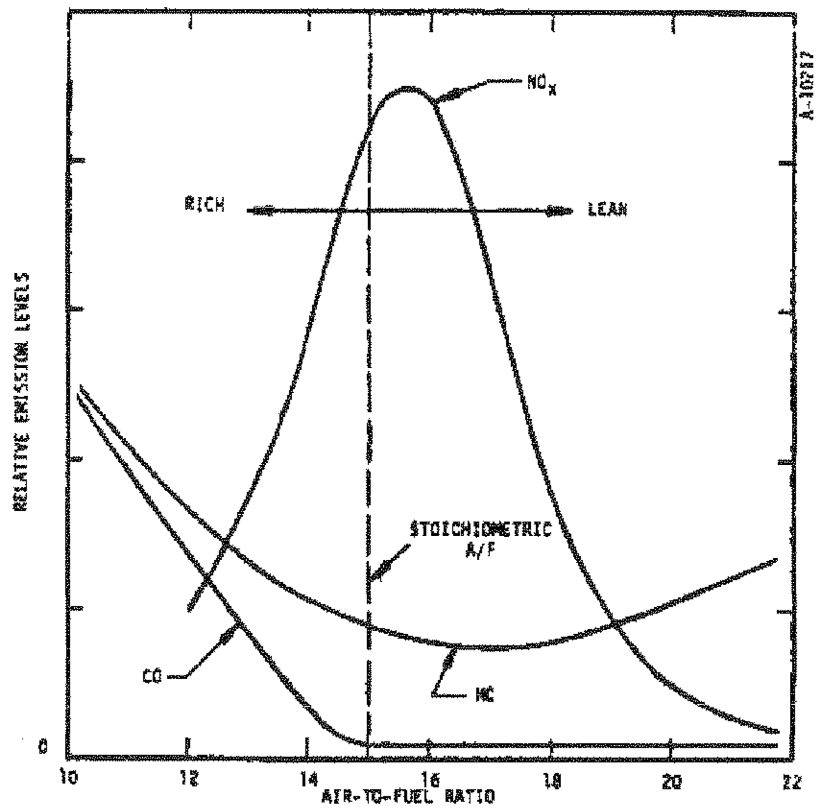


Figure CE2-1. The effect of air/fuel ratio on NOx, CO and VOC (HC).

The low-oxygen environment also contributes to incomplete combustion, which results in lower combustion temperatures and, therefore, lower NO_x formation rates. The incomplete combustion also increases CO emissions and, to a lesser extent, VOC (HC) emissions. Combustion efficiency is also reduced, which increases brake-specific fuel consumption (BSFC). Excessively rich A/F's may result in combustion instability and unacceptable increases in CO emissions.

The A/F can be adjusted on all new or existing rich-burn engines. Operating the engine on the lean side of the NOx formation peak is often preferred over operating rich because of increased fuel efficiencies associated with lean operation. Sustained NO_x reduction with changes in ambient conditions and engine load, however, is best accomplished with an automatic A/F control system.

The achievable NO_x emission reduction ranges from approximately 10 to 40 percent from uncontrolled levels. Based on an average uncontrolled NO_x emission level of 15.8 g/hp-hr the expected range of controlled NO_x emissions is from 9.5 to 14.0 g/hp-hr. Available data show that the achievable NO_x reduction using A/F varies for each engine model and even among engines of the same model, which suggests that engine design and manufacturing tolerances influence the effect of A/F on NO_x emission reductions.

Other Impacts

Another factor to consider in using A/F is that of engine load. At extremely low engine loads, such as those encountered in well-head natural gas may not be able to properly control the air-fuel ratio. In these situations other control technologies may be preferable to compressors operating in fields in which the field pressure is low, the A/F

Reference:

Stationary Reciprocating Internal Combustion Engines, Alternative Control Techniques Document, EPA-453/R-93-032

CE-3 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines

Control Measure Name: Ignition Timing Retard (ITR)

Applicable Regulation:

Application: This control measure applies to Spark Ignition and Compression Ignition engines.

Pollutants: NOx

Control Efficiency: NOx: 15 to 30%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis:
Cost information is summarized in the table below.

Table CE-3-1. Capital, O&M and annualized costs by engine horsepower. (CARB, 2001b)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	N/A	300	$300
151 - 300	N/A	450	$450
301 - 500	N/A	500	$500
501 - 1000	N/A	800	$800
1001 - 1700	N/A	900	$900

Cost Effectiveness: $42/ton-NOx – $1,210/ton-NOx

Status: Demonstrated

Control Measure Description: This technique can be used in all spark-ignited (SI) engines as well as compression-ignited engines. Retarding the ignition timing is based on retarding the timing to delay initiation of combustion to later in the power cycle. This method increases the volume of the combustion chamber and reduces the residence time of the combustion products thereby reducing the magnitude and duration of peak temperatures. This in turn has the potential for reduced NOx formation. The extent to which the ignition timing can be retarded to reduce NOx emissions varies for each engine, as ITR can increases exhaust temperatures, which may adversely impact exhaust valve life and turbocharger performance, and extreme levels of ITR may result in combustion instability and a loss of power. Brake-specific fuel consumption increases. While the maximum power output of the engine is reduced, this reduction is generally minor. In addition, emissions will increase. (CARB, 2001b)

Ignition timing can be adjusted on all new or existing rich-burn engines. Sustained NOx reduction with changes in ambient conditions and engine load, however, is best accomplished using an electronic ignition control system.

The achievable NOx emission reduction ranges from virtually no reduction to as high as 40 percent. For CI engines retarding the injection timing by about 4 degrees can reduce NOx by 15 to 30 percent. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr, the expected range of controlled NOx emissions is from 9.5 to 15.8 g/hp-hr. Available data and information provided by engine manufacturers show that, like AFR, the achievable NOx reductions using ITR are engine-specific.

CE- 4 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines

Control Measure Name: Air Fuel Ratio (AFR) and Ignition Timing Retard (ITR)

Applicable Regulation:

Application: This control measure applies to Spark Ignition and Compression Ignition engines.

Pollutants: NOx

Control Efficiency: NOx: 10 to 40%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost from Stationary Reciprocating Internal Combustion Engines, Alternative Control Techniques Document, EPA-453/R-93-032. Cost information is summarized in the table below.

Table CE-4-1. Capital, O&M and annualized costs by engine horsepower. (EPA, 1997)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	4,200	300	$984
151 - 300	5,000	450	$1,264
301 - 500	5,000	500	$1,314
501 - 1000	5,300	800	$1,663
1001 - 1500	5,300	900	$1,763

Cost Effectiveness: $105/ton-NOx – $3,571/ton-NOx

Status: Demonstrated

Control Measure Description: The combination of AF and IR can be used to reduce NO_x emissions. Available data and information from engine manufacturers suggest that the achievable NO_x emission reduction for the combination of control techniques is approximately the same as for AF alone (i.e., 10 to 40 percent) but offers some flexibility in achieving these reductions. Since parametric adjustments affect such operating characteristics as fuel consumption, response to load changes, and other emissions (especially CO), the combination of AF and IR offers the potential to reduce NO_x emissions while minimizing the impact on other operating parameters.

Other Reference:

Stationary Reciprocating Internal Combustion Engines, Alternative Control Techniques Document, EPA-453/R-93-032

CE- 5 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines

Control Measure Name: Prestratified Charge (PSC)

Applicable Regulation:

Application: This control measure converts rich-burn engines to lean-burn engines

Pollutants: NOx

Control Efficiency: NOx: 80%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table CE-5-1. Capital, O&M and annualized costs by engine horsepower. (CARB, 2001b)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	10,000	1,000	$2,627
151 - 300	23,000	1,500	$5,243
301 - 500	30,000	2,000	$6,882
501 - 1000	36,000	2,500	$8,359
1001 - 1500	47,000	3,000	$10,649

Cost information from Reference 3.

Cost Effectiveness: $136/ton-NOx – $2,979/ton-NOx

Status: Demonstrated

Control Measure Description: This control method converts rich-burn engines into lean burn engines. This add-on control technique facilitates combustion of a leaner air-fuel mixture. The major components of a PSC retrofit are the air injectors. The injectors pulse air into the intake manifold in such a fashion that layers or zones of air and the air/fuel mixture are introduced into the combustion chamber. The increased air content acts as a heat sink, reducing combustion temperatures, thereby reducing NO_x formation rates. Because this control technique is installed upstream of the combustion process, PSC is often used with engines fueled by sulfur-bearing gases or other gases (e.g., sewage or landfill gases) that may adversely affect some catalyst materials.

Prestratified charge applies only to four-cycle, carbureted engines. Pre-engineered, "off-the-shelf" kits are available for most new or existing candidate engines, regardless of age or size.

PSC has been installed on engines ranging in size up to approximately 2,000 hp. PSC can achieve greater than 80 percent control for NOx for power outputs up to about 70 to 80 percent of maximum.

Controlled NO_x emission levels of 2 g/hp-hr have been guaranteed, and available test data show numerous controlled levels of 1 to 2 g/hp-hr. The extent to which NO_x emissions can be reduced is determined by the extent to which the air content of the stratified charge can be increased without excessively compromising other operating parameters such as power output and CO and HC emissions.

Other Impacts: The leaner A/F effectively displaces a portion of the fuel with air, which may reduce power output from the engine. For naturally aspirated engines, the power reduction can be as high as 20 percent. This power reduction can be at least partially offset by modifying an existing turbocharger or installing a turbocharger on naturally aspirated engines. In general, CO and HC emission levels increase with PSC, but the degree of the increase is engine-specific. The effect on BSFC is a decrease for moderate controlled NO_x emission levels (4 to 7 g/hp-hr), but an increase for controlled NO_x emission levels of 2 g/hp-hr or less.

Other Reference:

Stationary Reciprocating Internal Combustion Engines, Alternative Control Techniques Document, EPA-453/R-93-032

CE- 6 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines

Control Measure Name: Low Emissions (L-E)

Applicable Regulation:

Application: This control measure applies to all Spark-Ignition Engines

Pollutants: NOx

Control Efficiency: NOx: 80%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table CE-6-1. Capital, O&M and annualized costs by engine horsepower. (CARB, 2001b)[1]

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	14,000	N/A	$2,278
151 - 300	24,000	N/A	$3,906
301 - 500	24,000	N/A	$3,906
501 - 1000	63,000	N/A	$10,253
1001 - 1500	148,000	N/A	$24,086

[1] Note: It is not likely that this measure will impact well-head compressor engines because this technology is generally applicable to engines larger than 500 hp and most, if not all well-head compressor engines are less than 500 hp.

Cost Effectiveness: $101/ton-NOx – $2,583/ton-NOx

Status: Demonstrated

Control Measure Description: This method has the potential to be used on all spark-ignition engines, but may not be offered by all manufacturers. The method is used to enhance the air/fuel ratio previously described. Basically, the leaner the mixture the lower the NOx emissions. However, to obtain substantial reductions, engine modifications are needed to assure that the fuel will ignite and to minimize fuel consumption penalties. Engine manufacturers have developed low-emission combustion designs (often referred to as torch ignition, or jet cell combustion) that operate at much leaner A/F's than do conventional designs. These designs incorporate improved swirl patterns to promote thorough air/fuel mixing and may include a precombustion chamber (PCC). A PCC is an antechamber that ignites a relatively fuel-rich mixture that propagates to the main combustion chamber. The high exit velocity from the PCC promotes mixing and complete

combustion of the lean A/F in the main chamber, effectively lowering combustion temperatures and, therefore, NO_x emission levels.
Low-emission combustion designs are available from engine manufacturers for most new SI engines, and retrofit kits are available for some existing engine models. For existing engines, the modifications required for retrofit are similar to a major engine overhaul, and include a turbocharger addition or upgrade and new intake manifolds, cylinder heads, pistons, and ignition system. The intake air and exhaust systems must also be modified or replaced due to the increased air flow requirements. The majority of engines that use this technology are in excess of 500 hp. Engine manufacturers do not offer lean burn engines in smaller size ranges (generally less than 300 hp).

Controlled NO_x emission levels reported by manufacturers for L-E are generally in the 2 g/hp-hr range, although lower levels may be quoted on a case-by-case basis. Emission test reports show controlled emission levels ranging from 1.0 to 2.0 g/hp-hr. Overall this technology has the potential to achieve 80 % reduction when combined with other NOx reduction techniques (i.e., precombustion chamber, ignition system improvement, turbo charging, air/fuel ratio controller) (CARB, 2001b). Information provided by manufacturers shows that, in general, BSFC decreases slightly for L-E compared to rich-burn designs, although in some engines the BSFC increases. An engine's response to increases in load is adversely affected by L-E, which may make this control technique unsuitable for some installations, such as stand-alone power generation applications. The effect on CO and HC emissions is a slight increase in most engine designs.

Other Impacts: Information provided by manufacturer's shows that, in general, BSFC decreases slightly for L-E compared to rich-burn designs, although in some engines the BSFC increases. An engine's response to increases in load is adversely affected by L-E, which may make this control technique unsuitable for some installations, such as stand-alone power generation applications. The effect on CO and HC emissions is a slight increase in most engine designs.

CE- 7 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines

Control Measure Name: **Selective Catalytic Reduction (SCR)**

Applicable Regulation:

Application: This control measure applies to lean-burn engines.

Pollutants: NOx

Control Efficiency: NOx: 80%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table CE-7-1. Capital, O&M and annualized costs by engine horsepower. (CARB, 2001b)[1]

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	45,000	20,000	$27,324
151 - 300	45,000	26,000	$33,324
301 - 500	60,000	35,000	$44,765
501 - 1000	149,000	78,000	$102,249
1001 - 1700	185,000	117,000	$147,108

[1] Note: This measure will apply only to larger well-head compressor engines (>300 hp) since manufactures do not provide lean-burn engines in the less than 300 hp range.

Cost Effectiveness: $865/ton-NOx – $30,985/ton-NOx

Status: Demonstration Limited in Remote Applilcations

Control Measure Description: SCR is a proven technology for many combustion devices but only applicable as a NOx emissions reduction technique for lean-burn gas engines and diesel engines. Selective catalytic reduction is an add-on control technique that injects urea $(NH_2)_2CO$ or ammonia (NH_3) into the exhaust, which reacts with NO_x to form N_2 and H_2O in the catalyst reactor. The two primary catalyst formulations are base-metal (usually vanadium pentoxide) and zeolite. Spent catalysts containing vanadium pentoxide may be considered a hazardous material in some areas, requiring special disposal considerations. Zeolite catalyst formulations do not contain hazardous materials. The exhaust of lean-burn engines contains high levels of oxygen and relatively low levels of VOC and CO, which make the NSCR type catalyst ineffective at reducing NOx. SCR performs best when the oxygen level in the exhaust exceeds 2 to 3 percent.

Selective catalytic reduction applies to all lean-burn SI engines and can be retrofit to existing installations except where physical space constraints may exist. As is the case for NSCR catalysts, fuels other than pipeline-quality natural gas may contain contaminants that mask or poison the catalyst, which can render the catalyst ineffective in reducing NO_x emissions. Catalyst vendors typically guarantee a 90 percent NO_x reduction efficiency for natural gas-fired applications, with an ammonia slip level of 10 ppmv or less. One vendor offers a NO_x reduction guarantee of 95 percent for gas-fired installations. Based on an average uncontrolled NO_x emission level of 16.8 g/hp-hr, the expected controlled NO_x emission level is 1.7 g/hp-hr. Emission test data show NO_x reduction efficiencies of approximately 80 to 95 percent have been reported for existing installations (NESCAUM, 2000).

Other Impacts: Variable duty cycles result in exhaust temperatures that may fall outside the ideal catalyst temperature and result in variable NOx emissions that require correspondingly variable ammonia flow rates. Ammonia slip levels for manually adjusted ammonia injection control systems and ranged from 20 to 30 ppmv (EPA, 1997). Carbon monoxide and HC emission levels are not affected by implementing SCR. The engine BSFC increases slightly due to the backpressure on the engine caused by the catalyst reactor. It should also be noted that some additional effort for engines using this technology and that are located in remote areas to be sure that ammonia slip does not occur.

CE- 8 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines

Control Measure Name: **Replacement of Older Engines with L-E Engine or Electric Motor**

Applicable Regulation:

Application: This control measure applies to all compressor engines.

Pollutants: NOx

Control Efficiency: NOx: 60 to 100%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table CE-8-1. Capital, O&M and annualized costs by engine horsepower. (CARB, 2001b)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	14,000	unknown	$4,492
151 - 300	24,000	unknown	$8,023
301 - 500	40,000	unknown	$12,839
501 - 1000	90,000	unknown	$28,855

Cost Effectiveness: $103/ton-NOx – $4,743/ton-NOx

Status: Demonstrated

Control Measure Description: Another method of reducing NOx emissions is to replace the existing engine with an electric motor or a new engine designed to emit very low NOx emissions. However, in the case of compressor engines, it may also be necessary to make other modifications to accommodate the new type of engine. Significant emissions reductions on the order of 60% can be achieved depending on the age and type of engine that is being replaced. The Four Corners Air Quality Task Force has discussed the option of Industry Collaboration to replace older compressor engines, particularly those associated with natural gas compression that are less than 200 hp.

This would require companies to commit to ordering new engines over a prescribed time likely ahead of when the older units would have been replaced. Another approach is to replace the engine with an electric motor. An electric motor essentially eliminates NOx emissions associated with the removed engine although there may be minor increases in power plant emissions to supply the additional electricity for the electric motors. Limitations of this technique include the remote locations where many compressor engines are located and therefore the lack of electric power. The costs of engine replacement with an electric motor or new low emissions engine are highly variable, depending on the size of the engine, the cost of electricity, electric power availability, remaining useful life of the existing engine and other factors.

There are multiple variables to be considered in calculating the cost of electrification. For example, when looking at the impact on electrical loads from central station power plants, we would need to consider that many of the coal-fired power plants are undergoing Best Available Retrofit Technology (BART) analysis by their permitting agency, which could reduce SOx and NOx emissions per MWhr by large margins over the next several years. In addition, there are multiple factors to consider in converting an individual engine at a specific location including engine size, availability and distribution network for electricity, among others. The cost estimates presented in this measure provide an informational review of the likely costs of electrification, but do not make an exhaustive analysis or consider the impacts from increased electrical loads from central station power plants.

Another option under discussion by the Four Corners Air Quality Task Force (4CAQTF)is the optimization and or Centralization of compressor engines. This option would evaluate the deployment of engines used in various oil and gas operations with the appropriate horsepower rated to the need of the activity being conducted. Overall, the approach would theoretically reduce the cumulative horsepower deployed and thereby reduce the emissions. This may also be accomplished by using larger central compression in lieu of deploying numerous well head compressor engines. The attraction of this option is that many of the compressor engines were sized based on field conditions that existed at the time of purchase but field conditions have changed and many well-head compressor engines are operating at low load factors. Further, the use of larger centralized compressor engines increases the opportunity to use low emissions lean-burn engines. The difficulty with this option is that field conditions are continuously changing and optimizing field equipment would require numerous iterations as field conditions change. In some mature fields with low field pressures this measure may not be feasible as losses in pressure from a central compression station may cause the central compression design to be unable to provide sufficient compression.

The Four Corners Air Quality Task Force concluded that compressor optimization would not result in any measurable reduction in emissions. This conclusion for new engines was based on the follow assumptions:

1) Current lease agreements for production cannot be easily changed.
2) Engine emission factors do not change with load.
3) Emission factors on small engines are consistent with large engines (proposed NSPS will require this).

Other References: Determination of Reasonably Available Control Technology and Best Available Control Technology for Stationary Spark-Ignited Internal Combustion Engines, California Air Resources Board, November 2001.

DRE- 1 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: Ignition Timing Retard (ITR)

Applicable Regulation:

Application: This control measure applies to Diesel Fired Drilling Rig Engines

Pollutants: NOx 15 to 30 %

Control Efficiency: NOx:

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below. Injection Timing Retard Capital Costs = \$12,200 for engines up to 1,000 hp and \$16,300 for engines 1001 to 2500 hp, Annualized cost based on an average of 6,000 operating hours per year using the formula: \$5,680 + (\$6.9 x hp).

Table DRE-1-1. Capital, O&M and annualized costs by engine horsepower. (EPA, 1997)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	12,200	Incl	\$6,600
151 - 300	12,200	Incl	\$7,236
301 - 500	12,200	Incl	\$8,443
501 - 1000	12,200	Incl	\$10,858
1001 - 1500	16,300	Incl	\$14,308

Cost Effectiveness: \$1,034/ton-NOx – \$2,243/ton-NOx

Status: Demonstrated

Control Measure Description: Injection timing retard in CI engines reduces NO_x emissions by the same principles as those for SI engines and is discussed in the discussion on compressor engines. Injection timing can be adjusted on all new or existing CI engines. Electronic injection control systems are used to maintain NO_x reductions. The control systems automatically adjust the timing for changes in ambient conditions and engine load.

Available data and information provided by engine manufacturers show that the achievable NO_x reductions using ITR is engine-specific but generally ranges from 20 to 30 percent. Based on an average uncontrolled NO_x emission level for diesel engines of 12.0 g/hp-hr, the expected range of controlled NO_x emissions is from 8.4 to 9.6 g/hp-hr. For dual-fuel engines, the average uncontrolled NO_x emission level is 8.5 g/hp-hr (620 ppmv) and the expected range of controlled NO_x emissions is from 6.0 to 6.8 g/hp-hr.

Other Impacts:

Data for ignition timing retard show no definite trend for CO and HC emissions for moderate levels of ignition retard in diesel engines and a slight increase in these emissions in dual-fuel engines. The BSFC increases with increasing levels of ITR for both diesel and dual-fuel engines. Excessive timing retard results in combustion instability and engine misfire (EPA, 1997).

DRE- 2 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: Selective Catalytic Reduction (SCR)

Applicable Regulation:

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: NOx

Control Efficiency: NOx: 80 to 95%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below. SCR capital cost is estimated according to the formula \$187,000 + (\$98 x hp). Annual costs are based on average of 6,000 operating hours per year using the formula \$113,000 + (\$39.5 x hp).

Table DRE-2-1. Capital, O&M and annualized costs by engine horsepower. (EPA, 1997)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	196,800	Incl	$116,950
151 - 300	209,099	Incl	$121,907
301 - 500	226,249	Incl	$128,820
501 - 1000	260,549	Incl	$142,645
1001 - 1500	309,549	Incl	$162,395

Cost Effectiveness: \$3,019/ton-NOx – \$7,709/ton-NOx

Status: Demonstration Limited

Control Measure Description: Selective catalytic reduction applies to all CI engines and can be retrofit to existing installations except where physical space constraints may exist. This technology has been used in the last 15 years to significantly reduce NOx emissions. As discussed previously, the SCR system needs a chemical reagent or "reductant" to convert nitrogen oxides to molecular nitrogen and oxygen in the exhaust stream. The reductant is ammonia (NH_3), which is often generated from stored urea. This technology can reduce emissions from 65% to more than 90%. The reductant is added at a rate from an algorithm that estimates the amount of NOx present in the exhaust stream. The algorithm relates NOx emissions to engine operating conditions such as rpm and load. Both precious metal and base metal catalysts are used in SCR systems. Base metal catalysts (i.e., vanadium and titanium) are used for exhaust temperatures in the range of 450^0F to 800^0F. For higher temperatures (675^0F to

1100^{0}F) zeolite catalysts are often used. Precious metal catalysts may also be used at lower temperatures (350^{0}F to 550^{0}F).

Some base-metal catalysts utilize a guard bed upstream of the catalyst to catch heavy hydrocarbons that would otherwise deposit on the catalyst and mask the active surface. The SCR system is also often used in conjunction with a catalyzed diesel particulate filter which will remove particulate matter and some heavy hydrocarbons before they reach the SCR catalyst. In the past some catalysts were also susceptible to poisoning by sulfur (the maximum sulfur content of No. 2 diesel oil is 0.5 percent), but sulfur-resistant catalyst formulations are now available.

SCR is a California Air Resources Board-verified emission control technology for NOx reduction in off-road diesel engines (applicable to diesel-fired compressors and drill rig engines) (CARB, 2007b). Tests have already been conducted in Wyoming on SCR retrofits on typical drill rig engines, and these have reported up to 82% reduction in NOx emissions (ENSR, 2006). Zeolite catalyst vendors typically guarantee a NO_x reduction efficiency for CI engines of 90 percent or higher, with an ammonia slip of 10 ppmv or less. Base-metal catalyst vendors quote guarantees for CI engines of 80 to 90 percent NO_x reduction, with ammonia slip levels of 10 ppmv or less. Based on an average uncontrolled NO_x emission level of 12.0 g/hp-hr for diesel engines, the expected range of controlled NO_x emissions is from 1.2 to 2.4 g/hp-hr. For dual-fuel engines, the average uncontrolled NO_x emission level is 8.5 g/hp-hr and the expected range of controlled NO_x emissions is from 0.8 to 1.7 g/hp-hr. Emissions test data show NO_x reduction efficiencies of approximately 80 to 95 percent for existing installations

Other Impacts: With reduction efficiencies of 80 to 95 percent, ammonia slip levels range from 5 to 30 ppmv (ENSR, 2006). Carbon monoxide and HC emission levels are not affected by implementing SCR. The engine BSFC increases approximately 1 to 2 percent due to the backpressure on the engine caused by the catalyst reactor.

Concern over ammonia emissions from SCR systems requires precise control of the ammonia injection rate. This is normally accomplished with precision controllers for the ammonia or urea injection. However increases in ammonia or urea injection rate can occur when the exhaust gas temperatures are too cold for the SCR reaction to proceed, and this may lead to ammonia slippage.

DRE- 3 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: **Exhaust Gas Recirculation (EGR)**

Applicable Regulation:

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: NOx

Control Efficiency: NOx: 40%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table DRE-3-1. Capital, O&M and annualized costs by engine horsepower.

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	10,200	5,000	$6,660
151 - 300	23,000	5,000	$8,743
301 - 500	40,849	5,000	$11,648
501 - 1000	51,049	5,000	$13,308
1001 - 1500	127,545	5,000	$25,757

Cost Effectiveness: $781/ton-NOx – $1,959/ton-NOx

Status: Demonstrated

Control Measure Description: This technology offers an effective means of reducing NOx emissions from diesel engines. Low pressure and high pressure systems are available. Low pressure systems are most commonly used for retrofit applications because engine modifications are not required. This method involves recirculating a portion of the engine exhaust back to the turbo-charger inlet or in the case of naturally aspirated engines, to the intake manifold. In most cases, an inter-cooler lowers the temperature of the exhaust gases being re-circulated. The cooler re-circulated gases have a higher heat capacity than air and contain less oxygen than air which lowers the combustion temperature in the engine by acting as both a heat sink and a diluent, and therefore reducing NOx formation. This technology is usually combined with diesel particulate filters to assure that large amounts of particulate matter are not re-circulated into the engine. NOx reductions of approximately 40% have been reported in mobile source applications (NESCAUM, 2003).

DRE- 4 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: Crankcase Emission Controls (CEC)

Applicable Regulation:

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: PM

Control Efficiency: PM: 6 to 23%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table DRE-4-1. Capital, O&M and annualized costs by engine horsepower (Garett, J., 2007)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	1,100	438	$617
151 - 300	1,100	438	$617
301 - 500	1,100	438	$617
501 - 1000	1,900	438	$747
1001 - 1500	3,500	438	$1,008

Status: Demonstrated

Control Measure Description: Crankcase emissions of particulate matter can be reduced by installing a multi-stage filter on the crankcase breather vent on turbocharged engines. The crankcase breather is often vented to the atmosphere resulting in large amounts of particulate matter being vented to the atmosphere. NESCAUM (NESCAUM, 2003) reported that emissions from the breather in mobile source applications can exceed 0.7 g/bhp-hr during idling conditions even on later model vehicles, which accounts for up to 25% of total tailpipe PM emissions. The multi-stage filters consist of a filter housing, pressure regulator, a pressure relief valve and an oil check valve. A crankcase filtration system can remove up to 90% of the crankcase blowby PM emissions, or from 6% to 23% of total exhaust PM emissions (Donaldson Corporation, 2003).

DRE- 5 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: Diesel Particulate Filters (DPF)

Applicable Regulation:

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: PM, CO, HC

Control Efficiency: PM: 85%
CO: 90%
HC: 90%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table DRE-5-1. Capital, O&M and annualized costs by engine horsepower (Garett, J., 2007)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	8,000	5,000	$6,302
151 - 300	8,000	5,000	$6,302
301 - 500	8,000	5,000	$6,302
501 - 1000	16,000	5,000	$7,604
1001 - 1500	32,000	5,000	$10,208

Status: Demonstrated

Control Measure Description: Particulate matter (PM) from the exhaust of diesel engines can be reduced by diesel particulate filters (DPFs). This technology works both on stationary and mobile engines. Means are provided to either burn off or remove accumulated PM from the filters. Some systems burn off or oxidize the PM when exhaust temperatures are adequate. In some stationary applications, disposable filter systems are used. In recently designed systems, the filter must be removed or cleaned when backpressure limits are reached which may not be practical in all situations. Filter materials used include ceramic and silicon carbide materials, fiber wound cartridges, knitted silica fiber coils, ceramic foam, wire mesh, sintered metal substrates and temperature resistant paper in the case of disposable filters. Collection efficiencies range from 50% to over 90%. Several regeneration techniques are used to achieve efficient regeneration. These include catalyst-based regeneration using a catalyst applied to the surfaces of the filter to reduce the ignition temperation necessary to oxidize the particulate matter. Catalytic DPFs (also called CDPFs) are the most effective at oxidizing PM and are the most common type of DPF used in mobile source applications. Some work has begun to make DPFs compatible with off-road diesel engines, but to date suitable DPFs have not been designed for all categories of off-road engines. Sulfur in the diesel fuel affects the reliability, durability and emissions performance of catalyst-based diesel particulate filters in off-road applications in which high sulfur content fuel is encountered. However, with new EPA-mandated diesel sulfur level regulations expected to come into effect by 2010 this issue should be resolved by the 2018 scenario year considered here. When the duty cycle of the engine prohibits a regeneration temperature from being reached in the engine, catalytic regeneration is not possible. Other techniques used include an on-board fuel burner or electric heaters to provide sufficient exhaust temperatures to ignite accumulated particulate matter and regenerate the filter.

The type of DPF used depends on the fuel sulfur content, filter system, operating conditions and the control level desired. It should be noted that an additional benefit of the DPF is the reduction that is achieved in reducing toxic hydrocarbon emissions.

DRE- 6 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: **Diesel Oxidation Catalyst (DOC)**

Applicable Regulation:

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: PM, CO, HC

Control Efficiency: PM: 25%
CO: 90%
HC: 90%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below. Assume that DOC costs $2500 for equipment in 150-300 HP range, or average horsepower 238hp. Therefore the average DOC cost is $10.4/hp.

Table DRE-6-1. Capital, O&M and annualized costs by engine horsepower (Garett, J., 2007)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	1,040	0	$169
151 - 300	2,345	0	$382
301 - 500	4,165	0	$678
501 - 1000	7,805	0	$1,270
1001 - 1500	13,005	0	$2,117

Status: Demonstrated

Control Measure Description: Diesel oxidation catalysts are used to reduce PM, CO and HC. PM emissions are reduced by the chemical transformation of their soluble organic fraction to carbon dioxide and water. Different catalytic formulations can be used to target different pollutants more aggressively than others. The catalysts consist of steel housings that contain metal or ceramic structure which acts as a catalyst substrate. Catalyst materials include platinum, rhodium and palladium. Reductions in excess of 50% are readily achieved and in some cases approach 70% for some compounds. DOCs are virtually maintenance free but periodic inspections are advisable to assure that cell plugging is not occurring. As with DPFs, DOCs are also affected by sulfur. The sulfur content of the diesel fuel is therefore important in applying this technology. With sulfur, the catalyst can also oxidize the sulfur dioxide to form sulfates which add to the total particulate matter emissions. However, catalyst formulations have been developed to minimize the oxidation of sulfur dioxide. Overall, the lower the sulfur content of the fuel, the more opportunity to maximize the effectiveness of the technology.

DRE- 7 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: Lean NOx Catalyst (LNC)

Applicable Regulation:

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: NOx

Control Efficiency: NOx: 10 to 20 %

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table DRE-7-1. Capital, O&M and annualized costs by engine horsepower. (Swenson, T., Cleaire, 2007)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	17,225	5000	$7,543
151 - 375	17,225	5000	$7,543
375 - 450	19,590	5000	$7,928
450 - 600	24,496	5000	$8,726
601-1500	N/A	N/A	N/A

Cost Effectiveness: $1,366/ton-NOx – $3,401/ton-NOx

Status: Demonstrated

Control Measure Description: In a Lean NOx catalyst, NOx is converted to N_2 using a small amount of reductant (diesel fuel or other hydrocarbon reductant) injected into the exhaust. Other systems operate passively at reduced NOx conversion rates. In passive systems, catalyst substrates are often made of zeolite which is a porous material and can provide microscopic sites that are fuel/hydrocarbon rich where reduction reactions can take place. When using reductants, a HC to NOx ratio of up to 6:1 is needed to achieve optimal NOx reductions. NOx conversion rates are typically around 10 – 20 %. However, the fuel penalty can be about 3%. Two types of lean NOx catalysts are available: a low temperature catalyst based on platinum and a high temperature catalyst utilizing base metals such as copper. Each type of catalyst is capable of converting NOx over a narrow temperature range and can be combined to broaden the temperature range over which they convert NOx.

DRE- 8- CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: Fuel Switching

Applicable Regulation:

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: PM, CO, NOx

Control Efficiency: PM: 14% (Low sulfur diesel fuel)
NOx: 85 to 91% (Natural gas)
PM: 50 to 80% (Natural gas)
NOx: 20 % (Diesel Emulsions)
PM: 17% (Diesel Emulsions)
CO: 13% (Diesel Emulsions)
HC: 30 to 99% Increase (Diesel Emulsions)

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table DRE-8-1. Capital, O&M and annualized costs by engine horsepower.

	Horse Power Range	Capital Cost	O&M	Annualized Cost
Low Sulfur Diesel	50 - 150	N/A	N/A	$0
	151 - 300	N/A	N/A	$0
	301 - 500	N/A	N/A	$0
	501 - 1000	N/A	N/A	$0
	1001 - 1500	N/A	N/A	$0
	Horse Power Range	Capital Cost	O&M	Annualized Cost
NG	50 - 150	9500	0	$1,465
	151 - 300	9500	0	$1,465
	301 - 500	9500	0	$1,465
	501 - 1000	N/A	N/A	N/A
	1001 - 1500	N/A	N/A	N/A
	Horse Power Range	Capital Cost	O&M	Annualized Cost
Emulsion	50 - 150	TBD	N/A	TBD
	151 - 300	TBD	N/A	TBD
	301 - 500	TBD	N/A	TBD
	501 - 1000	TBD	N/A	TBD
	1001 - 1500	TBD	N/A	TBD

Cost Effectiveness: Low-sulfur diesel: TBD
NG: TBD
Emulsion: $4,509/ton-NOx – $11,627/ton-NOx

Status: Demonstrated

Control Measure Description:

Low Sulfur Diesel - Switching to Low Sulfur fuel can reduce engine particulate emissions from drill rigs. A manufacturers study conducted by the manufacturers (MECA, 2002) switching from 368 ppm sulfur fuel to 54 ppm sulfur fuel reduced engine PM emissions from 0.073 g/bhp-hr to 0.63 g/bhp-hr, or about 14% as measured over the Federal Test Procedure. As noted above, the US EPA is mandating the use of low-sulfur diesel fuel in on- and off-road CI engine applications and this mandate will be in effect by the 2018 scenario year considered in this analysis. Thus switching to low-sulfur diesel should be considered in conjunction with other control measures.

Natural Gas – Some producers have opted to install natural gas-fired engines when replacing existing drill rigs (ENSR, 2006). This option has some limitations because a natural gas fuel source must be readily available at the location of the drilling operations. If a natural gas supply is available in close proximity, there may be a cost savings in fuel, however, if installation of piping to transport the natural gas is required, this option may be significantly more expensive than diesel fuel. Initial estimates for NOx emissions reductions are 85% for Tier 1 engines and 91% for Tier 9 engines. In addition, natural gas engines will emit significantly less particulate matter with reductions of 50%-80% in PM emissions.

Diesel Fuel Emulsions – Diesel fuel emulsions use surfactant additives to encapsulate water droplets in diesel fuel to form a stable mixture which ensure that the water does not contact metal engine parts. This technology reduces peak engine combustion temperatures and increases fuel atomization and combustion efficiency. Depending on the size of the engine NOx reductions of approximately 20% can be achieved. In addition, particulate matter reductions of 17% and CO reductions of 13% have been reported (Four Corners Air Quality Task Force, 2007). However, HC emissions can significantly increase (30 to 99 %). This technology can be used in conjunction with a diesel oxidation catalyst to reduce the HC and CO emissions and further reduce PM emissions. Engines using this technology typically experience a 15% increase in fuel consumption and a 20% power loss at maximum engine hp. Fuel mixing and a storage unit would also be required.

Other Impacts: Diesel fuel emulsions have been verified by the California Air Resources Board (CARB) and EPA for use in warm-weather climates, but not yet verified for use in cold-weather climates. In cold weather, emulsions may have operational difficulties due to ice formation in the emulsion. Fuel emulsion manufacturers are currently working to develop a cold-weather blend of emulsified diesel fuel. In addition, some tests have shown engine wear and corrosion after long-duration use of emulsified fuels, but given the fairly rapid turnover of diesel engines in drill rigs this is not expected to be a significant issue.

DRE- 9- CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: Repowering/Replacing Engines

Applicable Regulation: By 2015 all large (> 750 hp) stationary and nonroad diesel engine must meet federal EPA Tier 4 standards.

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: PM, NOx, HC

Control Efficiency: NOx+NMHC: 87% (Tier 2 to Tier 4)
PM: 85% (Tier 2 to Tier 4)
NOx+NMHC: 85 % (Tier 3 to Tier 4)
PM: 85% (Tier 3 to Tier 4)

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table DRE-9-1. Capital, O&M and annualized costs by engine horsepower.

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	12500	0	$1,953
151 - 300	27560	0	$4,404
301 - 500	48560	0	$7,822
501 - 1000	90560	0	$14,657
1001 - 1500	150560	0	$24,422

Cost Effectiveness: Tier 2 to Tier 4: $933/ton-NOx – $2,383/ton-NOx
Tier 3 to Tier 4: $935/ton-NOx – $2,034/ton-NOx

Status: Not yet available (expected in 2011 for < 750 HP engines, 2014 for > 750 HP engines)

Control Measure Description:

Repowering/Replacing Engine –This measure refers to replacing a drilling rig with a new rig or replacing the engines of a drilling rig with new engines that will meet the Tier 4 nonroad engine standard at the time of purchase. All new stationary and nonroad diesel engines that are manufactured and purchased new in 2015 must meet the Tier 4 nonroad standards which represent significantly tighter emissions restrictions than Tier 2 or 3 standards. The NOx + NMHC emissions standards for Tier 4 engines represent a 87% reduction from Tier 2 standards and the PM emissions standards for Tier 4 engines represent a 85% reduction from Tier 2 standards. For large engines > 750 HP, there is no Tier 3 standard and so these engines will be Tier 2 engines at the time that engine replacement becomes viable. Given the expected lifetime of a drilling rig of 10 years, it is expected that in 2018 most of the drilling rig engines will be Tier 2 (for large engines) and Tier 3 (for smaller engines). It is expected that Tier 4 engines would achieve these emissions reductions through better engine design and through the use of after-treatment control technology, thus this technology should not be considered separately with these engines.

EAP- 1- CONTROL TECHNOLOGY WHITE PAPER

Source Category: Glycol Dehydration Units

Control Measure Name: **Optimize Glycol Circulation Rate, Electric Pump Installation, Flash Tank Separator**

Applicable Regulation:

Application: This control measure applies to well head glycol dehydration units

Pollutants: VOC

Control Efficiency: VOC: 33 to 67% (Optimize glycol circulation rate)
VOC: 67% (Electric pump installation)
VOC: 10 to 40% (Flash tank separator)

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

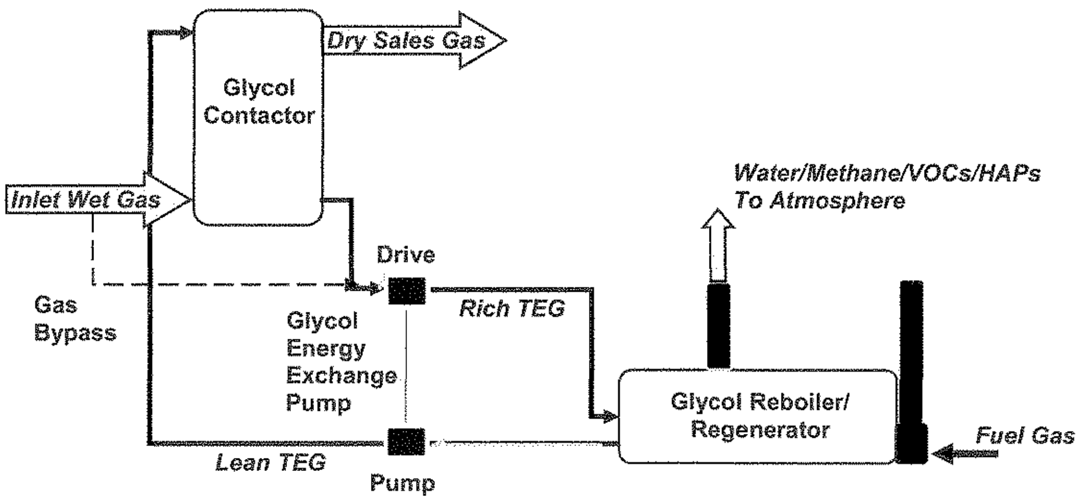
Cost Basis: Cost information is summarized in the table below. It was assumed that there would be no additional cost to operators for reducing the circulation rate (EPA, 2003c). For the electric pump installation, costs were based on a 3.0 hp electric pump, and the O&M costs for this pump include electricity cost ($200/yr), electric pump maintenance ($200/yr) and gas-assisted pump maintenance ($400/yr) (EPA, 2004a). Installation for different circulation rates was based on installing a flash tank separator on a dehydrator with an energy-exchange pump (EPA, 2003c).

Table EAP-1-1. Capital, O&M and annualized costs.

Technology	Size	Capital Cost	O&M	Annualized Cost
Optimize Circulation	NA	NA	NA	$0
Electric Pump	NA	1,853	2,176	$2,478
Flash Tank	30 gal/hr	5,160	Negligible	$840
Flash Tank	150 gal/hr	5,560	Negligible	$905
Flash Tank	300 gal/hr	7,160	Negligible	$1,165
Flash Tank	450 gal/hr	13,920	Negligible	$2,265

Status: Demonstrated

Control Measure Description: Produced natural gas usually contains saturated water which can condense and/or freeze in gathering, transmission and distribution piping causing plugging, pressure surges and corrosion. Dehydrators are used to remove water in the produced natural gas. This is done by passing the natural gas through a dewatering agent such as triethylene glycol (TEG), diethylene glycol (DEG) or propylene carbonate. The most common form used is the TEG, which absorbs water along with methane, VOCs and HAPs. The absorbed water and Hydrocarbons are then boiled off in a reboiler/regenerator and vented to the atmosphere. A diagram of the dehydration flow process diagram is shown in Figure EAP.1.



Source: Presentation on Minimizing Methane Emissions from Glycol Dehydrators, Offshore Technology Workshop, June 6, 2004

Figure EAP-1 Glycol dehydrator process diagram.

From the diagram, you can see that VOCs are vented to the atmosphere from the glycol Reboiler/Regenerator. As production rates decrease over time, glycol unit designed for the original production rates tend to over circulate causing emission increases without significant reduction in gas moisture content. Emission rates depend on the gas flow rate, the inlet and outlet water content, the glycol-to-water ratio, the percent over circulation and the methane entrainment rate. Also VOCs are emitted from the pneumatic control devices. Using a calculation from the EPA Natural Gas Star Lessons Learned (EPA, 2003a) that a 1 MMcfd TEG Glycol Dehydrator will emit 69 Mcf per year and the pneumatic control system will emit 504 Mcf per year (assuming 4 bleeding controllers). On average 600 Mcf of Methane is emitted from each glycol dehydrator per year. One producer has provided emissions estimates for glycol dehydrators at 97.93 lb/mmscf based on average operations using the Florida GlyCalc models. Estimates for dehydrator burners using AP-42 factors of 8.0 lb/mmscf. Several options are available to reduce or remove emissions of VOCs from dehydration operations. In addition to reducing emissions these options will result in methane savings, potentially lower operating costs and short-term paybacks in the control technology costs.

Optimize Glycol Circulation Rate

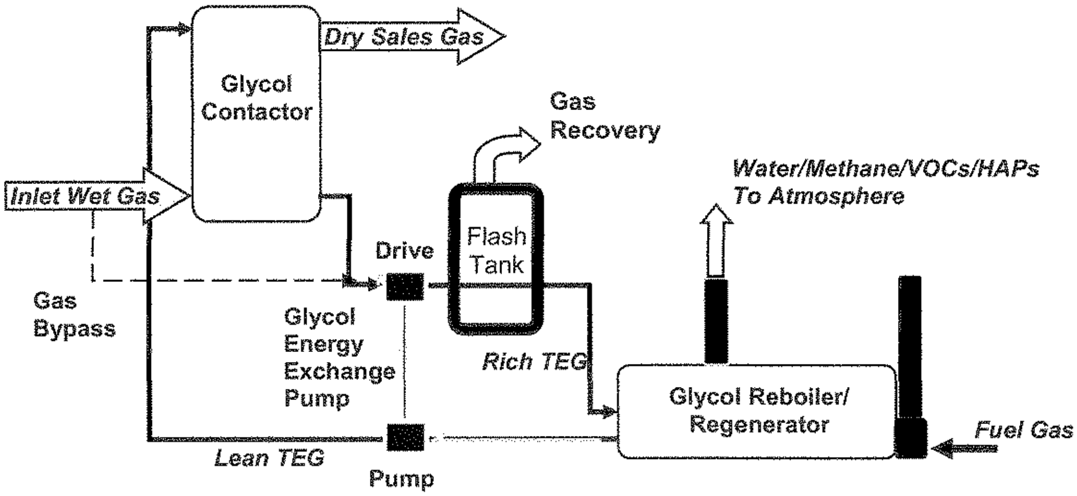
Natural Gas Star partners have found that dehydrator systems often circulate the TEG at rates two or more times greater than necessary (EPA, 2003c). Operators can reduce the TEG recirculation rate and significantly reduce emissions. TEG recirculation rates ranging from 45 to 2250 gal/hr that are reduced from 30 to 750 gal/hr show annual Methane reductions of 400 to 40,000 Mcf. In a glycol dehydrator, the water removal rate is a function of the gas flow rate and the amount of water to be removed from the gas stream. The TEG to water ratio (how many gallons of TEG is required to absorb 1 pound of water) varies between 2 and 5 gallons of TEG per pound of water. Accepted rule-of-thumb rate is 3 gallons of TEG per pound of water.

Electric Pump Installation

To circulate the TEG through the dehydrator, circulation pumps are used. The most common pump used in remote areas is a gas-assisted pump. These are basically pneumatic gas driven pumps designed to take advantage of the energy of high-pressure natural gas entrained in the rich (wet) TEG leaving the gas contactor. Additional high-pressure wet production gas is necessary for mechanical advantage, and therefore more methane rich gas is carried to the TEG regenerator where it is vented with the water boiled off the rich TEG. The mechanical design of these pumps places, wet, high pressure TEG opposed to dry, low pressure TEG,. Separated only by rubber seals. Worn seals result in contamination of the lean (dry) TEG making it less efficient in dehydrating the gas, requiring high glycol circulation rates. Typical emissions are about 1,000 cubic (Mcf) for each million cubic feet (MMcf) of gas treated. Replacing gas-assisted pumps with electric pumps increases system efficiency and significantly reduces emissions. For example, a 10 MMcf per day dehydrator could save up to 3,000 Mcf of gas per year (EPA, 2004a). As a rule-of-thumb, for every volume of gas absorbed in the rich TEG leaving the contactor, two more volumes of gas must be added from wet feed gas to supply enough power in the driver for the lean TEG pump. Therefore, using either a piston or gear-type energy exchange pump triples the amount of gas entrained with the TEG and vented to the atmosphere when no Flash Tank Separator is used.

Flash Tank Separator

Most production and processing dehydrators send the glycol/gas mixture from the TEG circulation pump directly to the regenerator where all the methane and VOCs entrained with the rich TEG vent to the atmosphere. Some installations use Flash tank separators to separate the gas and liquid at low system pressure without added heat. At this low pressure the gas is rich in methane and lighter VOCs but water remains in solution with the TEG. The wet TEG largely depleted of methane and VOCs then flows to the glycol reboiler/regenerator where it is heated to boil off the adsorbed water and any remaining methane or VOCs. A system diagram is shown in Figure EAP.2.



Source: Presentation on Minimizing Methane Emissions from Glycol Dehydrators, Offshore Technology Workshop, June 6, 2004

Figure EAP-2. Glycol dehydration unit with flash tank separator.

One industry study found that flash tank separators were not used in 85 percent of dehydration units processing less than one MMscfd of gas, 60 percent of units processing one to five MMscfd of gas, and 30 to 35 percent of units processing over five MMscfd of gas (EPA, 2003c). The flash tank separates approximately 90 percent of the methane and 10 to 40 percent of the VOCs entrained in the TEG.

EAP- 2- CONTROL TECHNOLOGY WHITE PAPER

Source Category: Pneumatic Controls

Control Measure Name: **Instrument Air Controllers, Non-bleed devices**

Applicable Regulation:

Application: This control measure applies to well head pneumatic controls

Pollutants: VOC

Control Efficiency: VOC: 98%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below. The costs for air controllers are based on a medium-sized installation (125 cfm compressor, 400 gallon tank, 60 cfm air dryer). The O&M costs for this technology include compressor service ($1200), air dryer replacement ($2,000) and electric service ($0.075/kWh) (EPA, 2004e). Cost information for non-bleed devices is based on a BP America program to reduce greenhouse gas emissions by retrofitting 4860 controllers at 1300 wells at a cost of $400 per controller (Smith, G.R., 2000).

Table EAP-2-1. Capital, O&M and annualized costs.

Technology	Size Range	Capital Cost	O&M	Annualized Cost
Instrument Air	NA	45750	16,340	$23,786
Non-bleed	NA	1,495	Negligible	$243

Status: Demonstrated

Control Measure Description: A variety of process control devices are used by the natural gas industry to operate valves that regulate pressure, flow, temperature and liquid levels. These instruments can be classified as pneumatic, electrical or mechanical devices. Most of the instruments used in production, however, are pneumatic devices, which make use of the available high-pressure natural gas onsite. Further, many of these sites do not have available electricity. These devices control and monitor gas and liquid flows, temperature in dehydrator regenerators and pressure in flash tanks. Most of the pneumatic control systems are operated at 20 to 30 psi and consist of a network of distribution tubing to supply all of the control instruments. Natural gas is also used for some utility services such as small pneumatic pumps, compressor motor starters and isolation shutoff valves.

As part of normal operation, natural gas powered pneumatic control devices release or bleed gas to the atmosphere and consequently, are a major source of methane emissions from the natural gas industry. According to BP (Frederick, J., Phillips, M., Smith, G.R., Henderson, C., Carlisle, B., 2000), these controllers were venting an average of 840 scf per day per controller. For BP operations, this amounted to 1.5 bcf of field gas per year.

Instrument Air Controllers

Significant emissions reductions can be achieved by converting natural gas-powered control systems to compressed instrument air systems. These systems substitute compressed air for pressurized natural gas, eliminating methane emissions and depending on the natural gas content VOC emissions. The benefits of this conversion is that existing pneumatic gas supply piping, control instruments and valve actuators can be reused when converting the compressed air systems. The downside of this type of system is the need for a compressor and therefore an electrical supply onsite. However, for those sites without electricity, emissions reductions can be achieved by replacing high-bleed devices with low bleed devices, retrofitting high-bleed devices and improving maintenance practices.

Replace Continuous-Bleed Controllers with Non-bleed Devices

In some cases, it is not practical to install instrument air controllers due to lack of onsite electrical power or other reasons. Replacing the continuous bleed controllers with non-bleed displacement-type controllers was demonstrated by BP to reduce the average venting to 12 scf of field gas per day, a reduction of over 98 percent from continuous-bleed devices. BP reported that they replaced about 70 percent of the continuous-bleed controllers in 1999 and the remainder in 2000. However there were, site-specific factors that prevented them from replacing all 4,900 controllers with the single-snap acting model that had been selected. These included controllers at wells producing dirty fluids that tended to foul the controller orifices or wells producing crude too light to trigger the controller's liquid dump valve. In some cases alternative non-bleed devices were selected and in other cases they were able to modify the controller or use retrofit kits to reduce bleed rates on existing controllers.

EAP- 3- CONTROL TECHNOLOGY WHITE PAPER

Source Category: Completion Venting and Flaring

Control Measure Name: **Flaring and Green Completion**

Applicable Regulation:

Application: This control measure applies to well head pneumatic controls

Pollutants: VOC

Control Efficiency: VOC: 62 to 98% (Flaring)
VOC: 70% (Green Completions)

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below. Note that this measure is not intended to be an installation option, but is included for reducing venting where flares are currently installed. The cost information is based on portable separators, sand traps and tanks that can recover an average of 2.5 barrels per well (EPA, 2004d).

Table EAP-3-1. Capital, O&M and annualized costs.

Technology	Size Range	Capital Cost	O&M	Annualized Cost
Flaring	NA	N/A	N/A	N/A
Green Completion	NA	180,000	1,000	$30,294

Status: Demonstrated

Control Measure Description: The last step in a well becoming a "producing well" is cleaning the well bore and the reservoir immediately surrounding the well. This "well completion" traditionally involves producing the well to open pits or tankage where sand, cuttings, and the reservoir fluids are collected for disposal and the produced natural gas is vented to the atmosphere. Venting the gas releases methane and depending on the composition of the gas other hydrocarbons and HAPs. Depending on the formation, natural gas may also contain nitrogen, carbon dioxide or sulfur compound such as hydrogen sulfide (H_2S). In the New Mexico portion of the San Juan Basin, there are at least 375 gas wells, from at least five different producing formations, that contain H_2S (Hewitt, J., 2005). Wellhead natural gas can range from 70 to 90 percent methane (EPA, 2004b). Several steps can reduce emissions from well completions.

Flaring

Flaring is used to convert natural gas to less hazardous and less reactive compounds. Flaring in the field has been shown to have lower efficiencies than typical flares used in refineries and other processes. While not many studies have been conducted, flares used in the field have shown to have efficiencies from 62% to 84% (Strosher, M., 1996). In addition, hydrocarbon byproducts may include VOCs considered Hazardous Air Pollutants (HAPs). Flares operated during well completion activities are required to handle large volumes of gas. The state of Wyoming has estimated the VOCs produced during a typical well completion. A single well completion event has been estimated to average 8 days and emit 115 tons of VOCs (assuming 100% venting). It is also estimated that 29 tons VOCs are released when flaring based on 50% of the gas being vented and a flare operating at an efficiency of 50% (Russell, J., Pollack A., 2006).

The results from one study conducted by the International Flare Consortium (IFC), showed that when the flares were operated under conditions representative of good industrial practice, the combustion efficiencies were >98% (McDaniel M., 1983). Exceptions occurred when intentionally excessive steam quenched the flame or when low Btu gases were intentionally flared at high velocity.

Green Completions

Green completions recover natural gas and condensate produced during well completions by using portable equipment that may include additional tanks, special gas-liquid-sand separator traps, and portable gas dehydration. The gas is directed through permanent dehydrators and meters to sales lines thereby reducing venting and flaring emissions. One EPA Gas Star Partner reported 70% reductions in the gas formerly vented to the atmosphere.

EAP- 4- CONTROL TECHNOLOGY WHITE PAPER

Source Category: Tanks

Control Measure Name: **Vapor Recovery Units, Convert Water Tank Blanket**

Applicable Regulation:

Application: This control measure applies to well head fugitive emissions

Pollutants: VOC

Control Efficiency: VOC: 95% (Vapor Recovery Unit)
VOC: Convert Water Tank Blanket (To be determined)

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below. The costs for a vapor recovery unit were estimated assuming that installations costs would be 75% of the unit cost and would recover 95% of the gas (EPA, 2003b). Costs for the water tank blanket were based on blanketing a 4,000 barrel water tank that is emptied twice per week. Capital cost was assumed to be in the middle of the $1,000 to $10,000 range (EPA, 2004c).

Table EAP-4-1. Capital, O&M and annualized costs.

Technology	Size Range	Capital Cost	O&M	Annualized Cost
VRU	25 Mcfd	26,470	5,259	$9,567
VRU	50 Mcfd	34,125	6,000	$11,554
VRU	100 Mcfd	41,125	7,200	$13,893
VRU	200 Mcfd	55,125	8,400	$17,371
VRU	500 Mcfd	77,000	12,000	$24,531
Water Blanket	NA	5,000	100	$914

Status: Demonstrated

Control Measure Description: Storage are used to hold oil for brief periods of time in order to stabilize flow between production wells and pipeline or trucking transportation sites. During storage, light hydrocarbons dissolved in the crude oil such as volatile organic compounds vaporize or "flash out" and collect in the space between the liquid and the fixed roof of the tank. As the level of the tank fluctuates, these vapors are often vented to the atmosphere. Underground crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the surface and processed, many of the dissolved lighter hydrocarbons and water are removed through a series of high pressure and low-pressure separators. The crude oil is then injected into a storage tank to await sale and transportation offsite. Losses of lighter hydrocarbons can occur by 1) flashing losses when the separator or heater-treater, operating at 35 psi, dumps oil into the storage tank at atmospheric pressure, 2) working losses released from the changing fluid levels and agitation of tank contents associated with the circulation of fresh oil through the storage tanks and 3) standing losses from daily and seasonal temperature changes. Vapor recovery units are installed on many of these tanks.

Vapor Recovery Units

Vapor recovery units (VRUs) can capture over 95 percent of the hydrocarbon emissions that accumulate in storage tanks. VRU systems typically draw hydrocarbon vapors out of the storage tank under low pressure and pipe the vapors to a separator to collect any liquids. The vapors are then routed through a compressor that provides low-pressure suction for the VRU system. VRUs are equipped with a control pilot to shut down the compressor and permit the back flow of vapors to the tank. The vapors are then metered and removed from the VRU system for pipeline sale or onsite fuel supply.

Convert Water Tank Blanket

Produced water is normally transferred to the fixed roof storage tank where the drop in pressure results in release of gases. This gas can also mix with the air in the tank to form an explosive mixture. Under this option, fixed rood tanks would be modified or new tanks would be installed to provide the capability of placing an inert gas blanket of the tanks to minimize vapor losses. This is accomplished by filling the space above the condensate/crude oil mixture to minimize VOCs from being emitted to the atmosphere.

EAP- 4- CONTROL TECHNOLOGY WHITE PAPER

Source Category: Tanks

Control Measure Name: Vapor Recovery Units, Convert Water Tank Blanket

Applicable Regulation:

Application: This control measure applies to well head fugitive emissions

Pollutants: VOC

Control Efficiency: VOC: 95% (Vapor Recovery Unit)
VOC: Convert Water Tank Blanket (To be determined)

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below. The costs for a vapor recovery unit were estimated assuming that installations costs would be 75% of the unit cost and would recover 95% of the gas (EPA, 2003b). Costs for the water tank blanket were based on blanketing a 4,000 barrel water tank that is emptied twice per week. Capital cost was assumed to be in the middle of the $1,000 to $10,000 range (EPA, 2004c).

Table EAP-4-1. Capital, O&M and annualized costs.

Technology	Size Range	Capital Cost	O&M	Annualized Cost
VRU	25 Mcfd	26,470	5,259	$9,567
VRU	50 Mcfd	34,125	6,000	$11,554
VRU	100 Mcfd	41,125	7,200	$13,893
VRU	200 Mcfd	55,125	8,400	$17,371
VRU	500 Mcfd	77,000	12,000	$24,531
Water Blanket	NA	5,000	100	$914

Status: Demonstrated

Control Measure Description: Storage are used to hold oil for brief periods of time in order to stabilize flow between production wells and pipeline or trucking transportation sites. During storage, light hydrocarbons dissolved in the crude oil such as volatile organic compounds vaporize or "flash out" and collect in the space between the liquid and the fixed roof of the tank. As the level of the tank fluctuates, these vapors are often vented to the atmosphere. Underground crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the surface and processed, many of the dissolved lighter hydrocarbons and water are removed through a series of high pressure and low-pressure separators. The crude oil is then injected into a storage tank to await sale and transportation offsite. Losses of lighter hydrocarbons can occur by 1) flashing losses when the separator or heater-treater, operating at 35 psi, dumps oil into the storage tank at atmospheric pressure, 2) working losses released from the changing fluid levels and agitation of tank contents associated with the circulation of fresh oil through the storage tanks and 3) standing losses from daily and seasonal temperature changes. Vapor recovery units are installed on many of these tanks.

Vapor Recovery Units

Vapor recovery units (VRUs) can capture over 95 percent of the hydrocarbon emissions that accumulate in storage tanks. VRU systems typically draw hydrocarbon vapors out of the storage tank under low pressure and pipe the vapors to a separator to collect any liquids. The vapors are then routed through a compressor that provides low-pressure suction for the VRU system. VRUs are equipped with a control pilot to shut down the compressor and permit the back flow of vapors to the tank. The vapors are then metered and removed from the VRU system for pipeline sale or onsite fuel supply.

Convert Water Tank Blanket

Produced water is normally transferred to the fixed roof storage tank where the drop in pressure results in release of gases. This gas can also mix with the air in the tank to form an explosive mixture. Under this option, fixed rood tanks would be modified or new tanks would be installed to provide the capability of placing an inert gas blanket of the tanks to minimize vapor losses. This is accomplished by filling the space above the condensate/crude oil mixture to minimize VOCs from being emitted to the atmosphere.

5. 2018 EMISSIONS FORECASTS

PROJECTION METHODOLOGY

Two methods were used to estimate 2018 county level oil and gas emissions. The first and by far the dominant method was to develop growth factors to project from the 2005 oil and gas county-level emissions described in the previous task. A second method was then necessary to estimate emissions in the counties that had no 2005 oil and gas emissions but are anticipated to see oil and gas development by 2018.

The growth factors used to project county level emissions from 2005 to 2018 were derived from projections of future oil and gas production reported by several sources. The preferred source of production projections was the Federal Bureau of Land Management (BLM), which prepares Resource Management Plans (RMPs) for the lands and mineral resources under its stewardship, and often oversees the preparation of Environmental Impact Statements (EIS). RMPs and EIS's for oil and gas production areas typically include an estimate of reasonably foreseeable oil and gas development (RFD). This was the same method employed in the previous Phase I analysis, which made use of the RMPs available at that time. In the current analysis the RMPs previously used were reviewed to determine if any revisions or updates had been made. Frequently, RMPs are modified by the BLM after a period of comment by public organizations, the petroleum industry, and state and federal governmental entities. The updates are often published in a Record of Decision (ROD) that may include modification of the RFD for a particular RMP. In addition to reviewing all RODs issued since the Phase I work, this current analysis also examined whether any new RMPs had been released covering geographic areas not previously considered. Table 5-1 below shows a summary of the RMPs considered for generating 2018 scaling factors and the minimum and maximum foreseeable development scenarios where available. The minimum and maximum well counts in an RFD were determined for calendary year 2018 by linearly interpolating the RMP prediction if the RMP plan extended beyond 2018, and used the published RFD scenario if that scenario was to be completed before 2018. Although only the average growth statistics were used to determine 2018 emissions projections, the minimum and maximum scenarios give an indication of the range of predicted activity. Figure 5-1 shows the geographic coverage of the RMPs used to generate 2018 scaling factors.

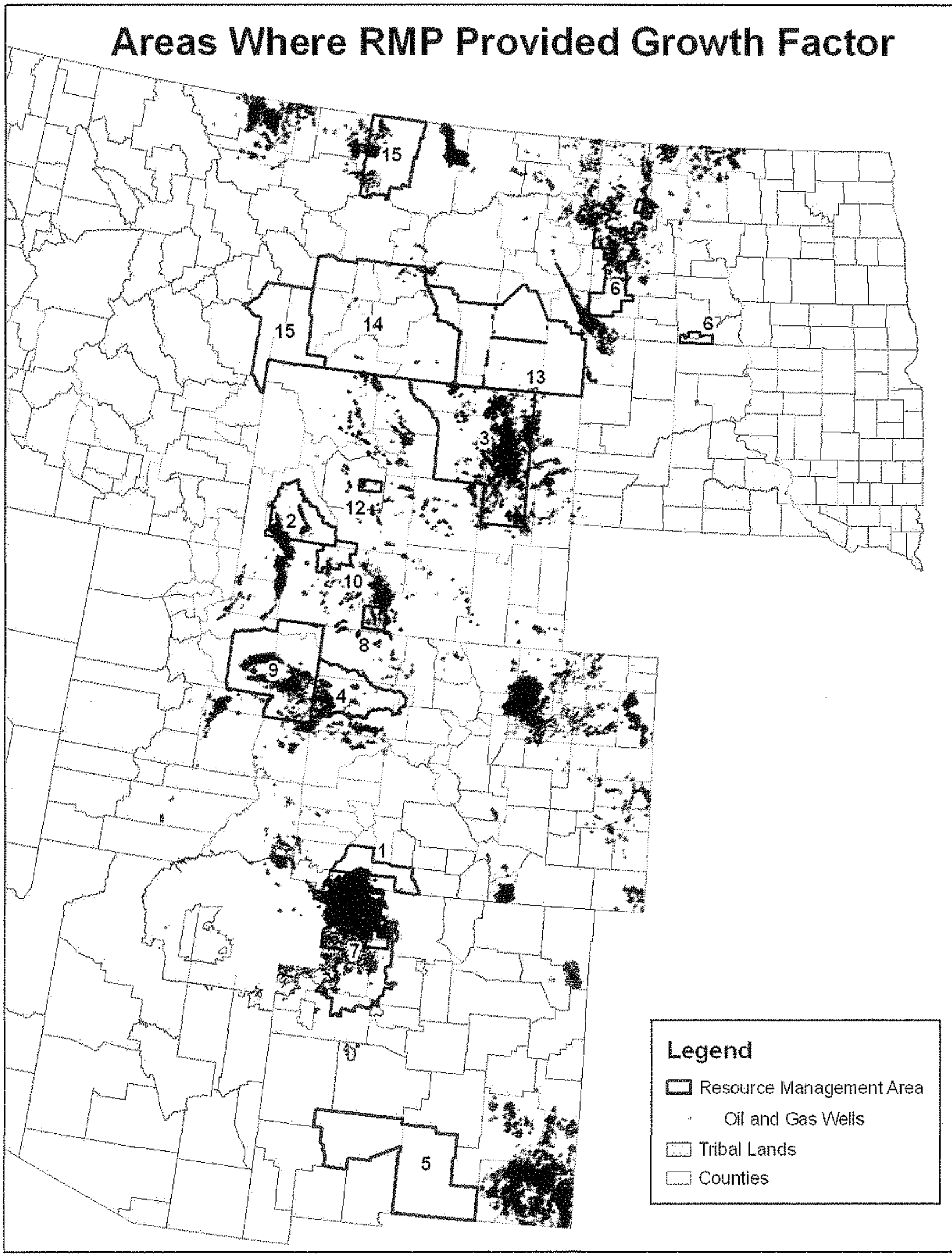


Figure 5-1. Geographic coverage of RMPs used to generate scaling factors for 2018 emissions projections. RMPs by number are listed in Table 5-1.

Table 5-1. BLM RMPs considered for use in generating 2018 scaling factors, and the predicted minimum and maximum well counts.

RMP Name	#	2018							
		Gas Wells		Oil Wells		CBM Wells		Comp. Stations	
		Min	Max	Min	Max	Min	Max	Min	Max
Northern San Juan Basin Coal Bed Methane Project*	1					117	514	6	15
Pinedale RMP	2	3,948	5,502						
Wyoming Powder River Basin Final EIS*	3	1,165	2,863			13,872	35,223	313	948
White River Resource Area RMP EIS	4		1,006						
RMP EIS for Mineral Leasing and Development in Sierra and Otero Counties*	5		27		37				
Dakota Prairie Grasslands Oil and Gas Leasing	6		655				87		
Farmington Proposed RMP and Final EIS	7	3,653	10,746	104	308	815	2,399		
Desolation Flats Natural Gas Field Development Project	8	51	275						
Draft Vernal Resource Management Plan	9		3,530		1,670		106		
Jack Morrow Hills Coordinated Activity Plan*	10	157	262			21	42		
Wind River Natural Gas Project	11	233	485						
Powder River and Billings RMPs – Powder River	12		610				13,867		
Powder River and Billings RMPs – Billings	13		190				4,876		
Powder River and Billings RMPs – Special Consideration	14		114						
Sweetwater and Carbon Counties, Wyoming*	15	805	2,857						

* Indicates RMPs for which updated information was available since the Phase I inventory analysis was conducted.

As shown in Table 5-1, the RMPs obtained covered a large portion of the WRAP production areas. In addition to the BLM studies, the Alaska Department of Natural Resources prepares 20-year production forecasts that were used in this effort (AK DNR, 2006). For the remaining areas, regional production forecasts published by the Energy Information Administration were used[3]. For those areas where EIA forecasts were the only source of data identified, separate oil and gas growth factors were calculated as the 2018 regional production forecast by the EIA divided by 2005 regional production reported by the EIA. There are three EIA growth regions in which some portion of emissions in that region were projected using EIA data. Growth factors developed for those regions based on the EIA's production forecasts are shown in Table 5-2.

Table 5-2. 2005 to 2018 oil and gas growth factors based on EIA forecasts.

Region	Oil Production	Gas Production
Rocky Mountain	1.5515	1.2072
Southwest	0.9852	1.0632
West Coast	1.0730	0.7232

Projections to 2018 based on the BLM RMPs or Alaska DNR data were made using growth factors derived from the proposed future development and the actual 2005 activity as developed in the scale-up of the baseline EI from 2002 to 2005. In order to estimate the future number of wells, both the number of wells installed and the number of wells plugged and abandoned had to be estimated. As the RMPs do not include estimates of the number of wells that will be plugged and abandoned in future years, OGC data were used to estimate the number of wells plugged and abandoned annually at the county level. The future number of wells in a production area was then estimated based on the number of existing wells in 2005, the number of new wells anticipated by the RMP and the estimated number of wells that would be plugged and abandoned based on the assumed persistence of historical well plugging rates.

For growth factors in counties that fall within an RMP area, it was necessary to intersect the RMP area boundaries with the counties' boundaries to determine the fraction of the county that lies within the RMP. This intersection was conducted using 2005 well counts and yielded three distinct conditions: counties entirely within an RMP area, counties partially within an RMP area and counties not in an RMP area. In counties completely within an RMP area, and counties not in an RMP area, the RMP-based growth factor and the EIA-based growth factor were used respectively. In the counties only partially intersected by an RMP area, it was necessary to apply RMP-based growth factors to the fraction of the wells in the RMP area and EIA-based growth factors to the remaining wells. This was done according to Equation 5-1.

Equation 5-1:

$$GF_{county} = \sum_{i}\left(\frac{N_{wells,RMP_i}}{N_{wells,county}} \times GF_{RMP_i}\right) + \frac{N_{wells,NON-RMP}}{N_{wells,county}} \times GF_{EIA}$$

where GF_{county} is the county growth factor (for counties with both RMP and non-RMP areas), N_{wells,RMP_i} is the number of wells in the county that lie within the boundaries of RMP i, $N_{wells,county}$ is the total number of wells in the county, GF_{RMP_i} is the growth factor for RMP i, $N_{wells,NON\text{-}RMP}$ is the number of wells in the county that do not lie within the boundaries of any RMP, and GF_{EIA} is the growth factor for the county based on the EIA.

It should be noted that it was not possible to derive growth factors based on well count for all cases where the 2002/2005 estimates were based on well count. RMPs were the only source of well count projections available, and the RMPs did not cover all areas for which the updated methodology in this analysis was applied. In addition, some counties' growth factors were a weighted average of both RMP-based and EIA-based growth factors, as described in Equation 5-1, which combines both a production-based and a count-based growth factor estimate. This was due to the limited number of RMPs available for the entire WRAP region.

For drilling activities, a separate growth factor was developed based on the predicted drilling activities in RMPs and a drilling-based growth factor from the 2007 Annual Energy Outlook[3]. In areas with coverage by an RMP, a separate growth factor was estimated for drill rig activity as the number of wells drilled per year suggested by the development scenario divided by the number of wells drilled in the same area in 2005. A growth factor for drilling in areas where EIA forecasts were used was determined based on the total predicted growth in well drilling in the lower 48 states as reported in the EIA forecast; regional drilling growth was not available. Based on the EIA information, a drill rig activity growth factor of 1.071 was calculated. To determine the drilling activity growth factor for counties lying partially within the boundaries of an RMP, a well-count weighted average of the drilling growth factors in the RMP and outside of the RMP was derived, in a manner similar to Equation 5-1.

Independent 2018 emissions estimates

There were counties for which there was predicted O&G activity in 2018, but no activity in 2005, and therefore a growth factor for these counties needed to be developed independently of the methodology described above. In cases of counties entirely or partially within an RMP area, an independent methodology was employed to estimate 2018 emissions.

For these counties, the fraction of 2005 wells within the county that were also within the RMP was determined by intersecting the county and RMP boundaries. This fraction was applied to the predicted RMP well count for 2018 to determine the predicted county-level number of wells in 2018. For each source category, the 2005 emissions per well were determined by totaling the 2005 emissions by pollutant for each source category and dividing by the number of wells. This was then multiplied by the number of predicted wells in 2018 to estimate the emissions from the RMP fraction of the county's wells in 2018. The remaining portion of the county outside of the RMP was assumed not to have any O&G activity in 2018, since it had no activity in 2005 and no RMP to indicate any planned future activity. It should be noted that for counties with no 2005 activity and no RMP, it was assumed that no future O&G activity would be assigned to that county.

Future Year Emission Controls

Implementation of new federal and state control programs will have a substantial impact on future emissions. Known "on the books" state and federal emissions control estimates were incorporated into the 2018 emissions projections. A summary of the controls identified and the actions taken to incorporate them into the 2018 projections is provided in Table 5-3. It should be noted that state controls in Wyoming and Utah were not applied to the baseline 2002/2005 emissions because it was assumed that the in-use equipment at that time predated the control regulations in both of these states. However, by 2018 it is assumed that 100% of the equipment would be subject to these state regulations.

Table 5-3. Future federal and state controls incorporated into the 2018 emissions projections.

State	Future Controls	Action
All	Federal onroad diesel engine standards (EPA, 2005b)	Used emissions standards information for 750+ hp drill rig engines from EPA's NONROAD model to adjust drill rig engine emissions for future performance standards
All	Federal nonroad spark-ignition engine standards (EPA, 2005b)	Used emissions standards information for natural gas fired nonroad engines (SCC 2268000000) from EPA's NONROAD model to adjust CBM pump engine emissions for future performance standards
All	Federal mandates for non-road diesel fuel sulfur content (EPA, 2000)	Used 2002 study by WRAP (Pollack, A., Chan, L., Chandraker, P., Grant, J., Lindhjem, C., Rao, S., Russell, J., Tran, C., 2006) to determine ratio of 2002 to 2018 non-road diesel fuel sulfur content and used this to develop scaling factors for SOx emissions from drilling rigs.
Wyoming	Best Available Control Technology (BACT) regulation requiring all permitted O&G sources in the state to emit no more than 1 g/bhp-hr NOx emissions.	The 2002/2005 emissions estimates per compressor engine were modified for 2018 by assuming this maximum BACT emissions factor. The ratio of 2018 per equipment emissions to 2002 per equipment emissions was estimated to derive a control factor by county in Wyoming.
Utah	BACT regulation requiring all permitted O&G sources in the state to emit no more than 1 g/bhp-hr NOx emissions.	A similar methodology to that in Wyoming was employed to generate control factors for Utah compressors.
Colorado	Regulation 7 requiring reductions in VOC emissions from oil and gas sources, controls requirements for compressor engines, tanks, and glychol dehydrators.	All wellhead compressors in Colorado are assumed to be part of Colorado's point source inventory and thus were not considered in this area source inventory.

The 2018 drill rig and CBM pump emissions were adjusted downward under the assumption that future equipment purchases will be required to meet the federal nonroad engine standards. The adjustment for drill rig emissions was performed by comparing the emission rates yielded by EPA's NONROAD model for 750+ horsepower drill rig engines in 2018 versus those for the same category in 2002; this ratio is based on the model's assumption about engine lifetimes and fleet turnover rates. For CBM pump engines, the adjustment was performed by comparing the emission rates given by the NONROAD model for natural gas fired engines in 2018 versus those for the same category in 2002. For drill rig SOx emissions, the ratio of 2018 non-road sulfur fuel content (assumed to be 15 ppm) to the by-county sulfur content of non-road diesel fuel in 2002 was determined. This determined the fraction of SOx emissions reductions for this source category, assuming all of the fuel sulfur would be emitted as SOx. In Wyoming and Utah, the 2002/2005 compressor engine estimates in the focus basins were modified under the assumption that the maximum emissions factor of NOx for these engines would be 1 g/bhp-hr. The county-level emissions per equipment were generated and a ratio was derived of the 2018 emissions to the 2005 emissions. This was used to derive a control factor which was applied to all compressor emissions in these two states.

2018 EMISSIONS ESTIMATES

The 2018 projected emissions for NOx and SOx are shown in Tables 5-4 and 5-5, respectively. The oil and gas point sources from the current WRAP emissions inventory are also shown below in Tables 5-4 and 5-5 for comparison, as well as the total of oil and gas point and area sources. Table 5-4 shows that for drilling rigs, Wyoming has the largest projected NOx emissions, followed by New Mexico and Colorado. This is due to the projection of 2018 emissions from a baseline year of 2005, when there was significant gas well drilling activity happening in Wyoming. For gas compressor engines, New Mexico has the greatest emissions due to the significant use of wellhead compression in the San Juan Basin. It should be noted that Colorado wellhead compressor emissions were not estimated because this equipment is counted in the Colorado point source inventory.

Table 5-4. NOx emissions estimates by source category for all WRAP states in 2018.

States	Drill Rigs	Oil Well - All Sources	Compressor Engines	Gas Well - All Sources	CBM Pump Engines	All Area Sources	All Point Sources	TOTAL
Alaska[a]	452	0		0		453	36,382	**36,835**
Arizona		0	8	7		15	382	**397**
California							10109	**10,109**
Colorado[b]	4,413	12	4,006	24,687	400	33,517	14,825	**48,342**
Idaho							1,734	**1,734**
Montana	2,821	126	3,946	6,987		13,880	2,533	**16,413**
Nevada	21	2	40	0		63	47	**110**
New Mexico	5,343	522	47,599	20,183	67	73,714	36,320	**110,034**
North Dakota	1,655	126	18,399	689		20,869	3,928	**24,797**
Oregon		0	37	7		44	753	**797**
South Dakota	118	6	368	66		557	311	**868**
Utah	944	122	164	5,066		6,297	1,930	**8,227**
Washington							247	**247**
Wyoming	9,883	147	655	22,449	1,008	34,142	9,075	**43,217**
WRAP Total	**25,652**	**1,063**	**75,222**	**80,140**	**1,475**	**183,551**	**118,576**	**302,127**

a – Wellhead compressors in Alaska are permitted as part of a central station and counted in the state point source inventory

b – Colorado's point source inventory threshold is 2 tpy NOx, which includes all wellhead compressors, therefore the only compressor emissions listed here for Colorado are those from the Southern Ute tribal lands.

Wellhead emissions sources from gas wells in Colorado include heaters, well completions and well flaring and venting, which were estimated in the Phase I work but not updated in this analysis. Any future emissions inventory effort should investigate these sources in more detail.

Table 5-5 shows that SOx emissions in the WRAP region are expected to be quite small in 2018 for the sources estimated, largely due to the phase-in of federally mandated low-sulfur fuel standards for non-road diesel fuel. Thus although a significant growth in activity was predicted for O&G drilling in the western U.S. by 2018, this is more than matched by the control factor caused by the new fuel.

Table 5-5. SOx emissions estimates by source category for all WRAP states in 2018.

States	Drill Rigs	Oil Well - All Sources	Compressor Engines	Gas Well - All Sources	CBM Pump Engines	All Area Sources	All Point Sources	TOTAL
Alaska[a]	1	0		0		1	79	**80**
Arizona		0	0	0		0	0	**0**
California							997	**997**
Colorado[b]	11	0	0	0	0	11	129	**140**
Idaho							10	**10**
Montana	6	0	0	0		6	16	**22**
Nevada	0	0	0	0		0	0	**0**
New Mexico	3	0	1	7	0	12	12,990	**13,002**
North Dakota	4	0	0	0		4	2,672	**2,676**
Oregon		0	0	0		0	8	**8**
South Dakota	0	0	0	0		0	15	**15**
Utah	1	0	0	0		1	0	**1**
Washington							4	**4**
Wyoming	3	0	0	0	0	3	6,420	**6,423**
WRAP Total	**29**	**0**	**1**	**7**	**0**	**38**	**23,340**	**23,378**

a – Wellhead compressors in Alaska are permitted as part of a central station and counted in the state point source inventory

b – Colorado's point source inventory threshold is 2 tpy NOx, which includes all wellhead compressors, therefore the only compressor emissions listed here for Colorado are those from the Southern Ute tribal lands.

It should be noted that some minor emissions are predicted from source categories that are only estimated in New Mexico, such as artificial lift engines and SWD engines. These source categories have been identified as a result of the NMED study in San Juan and Rio Arriba counties. Due to the focused effort of that EI, some equipment was identified which had not been inventoried in other regions of the WRAP domain. Future emissions inventories should include these source categories in all areas.

Figure 5-2 shows the estimated trend of NOx area source emissions from this analysis for the WRAP region for 2002, 2005 and 2018. In Wyoming, and to some extent Colorado and Utah, the effects of controls requirements on area source emissions categories can be observed, since in Wyoming area source emissions are predicted to decrease in 2018 as compared to 2005 despite increased growth in O&G activity. In Colorado and Utah the projected growth in area source emissions from 2005 to 2018 is quite small. North Dakota area source emissions are projected to jump dramatically from 2005 to 2018, largely due to the assumed implementation of the RFD in the Dakota Prairie Grasslands RMP. New Mexico area source emissions are predicted to continue to increase from 2005 to 2018.

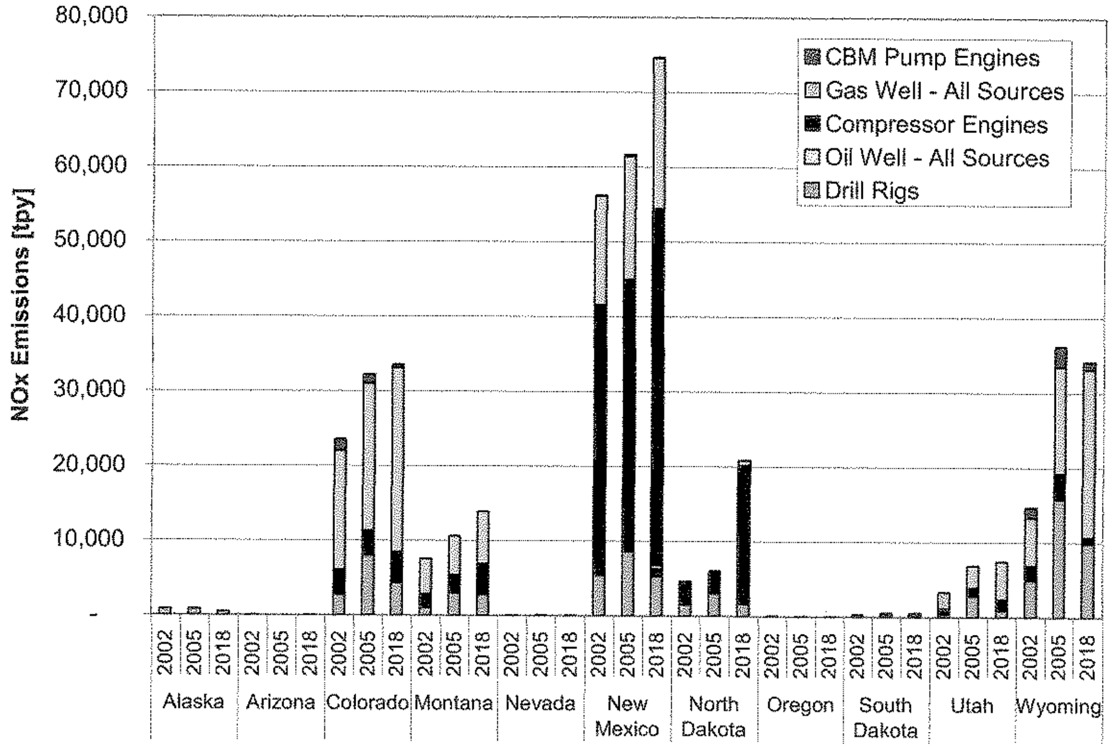


Figure 5-2. NOx area source emissions estimates by state in the WRAP region for 2002, 2005, and 2018.

Figure 5-3 shows the estimated trend of SOx area source emissions from this analysis for the WRAP region for 2002, 2005 and 2018. In all states the SOx area source emissions are predicted to grow significantly from 2002 to 2005 driven by large-scale oil and gas exploration in the WRAP region during this time frame. However, by 2018 these emissions are expected to decrease dramatically as the EPA-mandated phase-in of low sulfur non-road diesel fuel is put into effect. Drilling rig engines are by far the largest source of SOx area source emissions from all O&G area source categories.

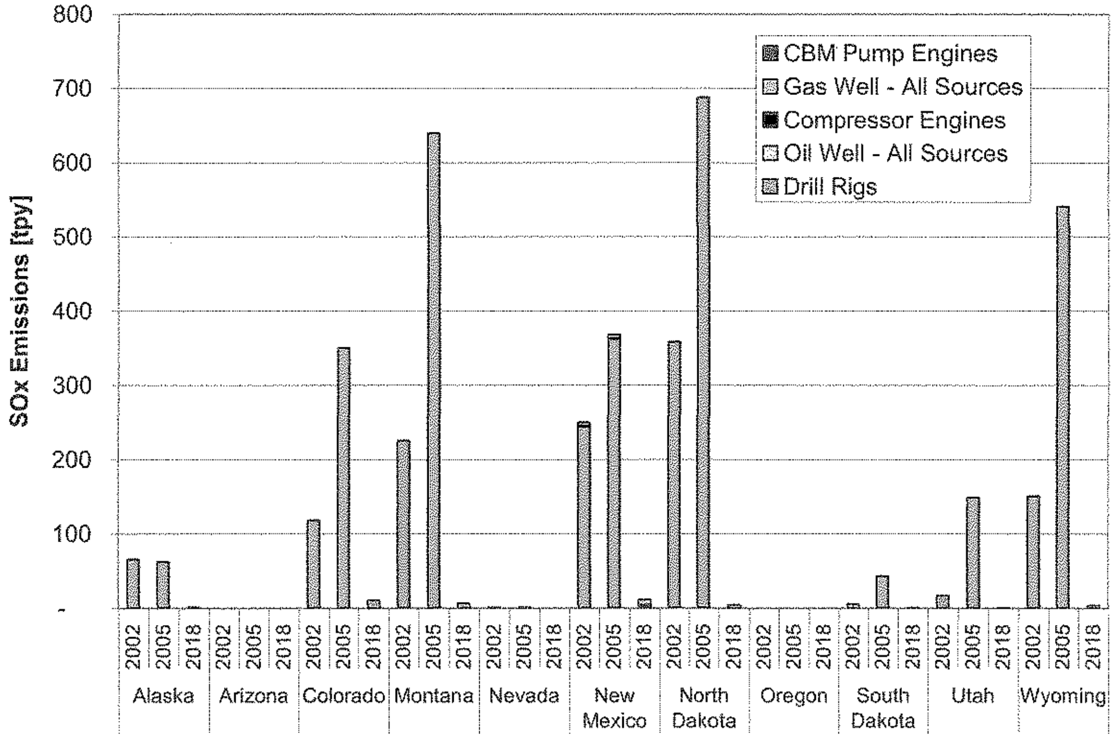


Figure 5-3. SOx area source emissions estimates by state in the WRAP region for 2002, 2005, and 2018.

Comparison of Phase I and Phase II 2018 Estimates

Figure 5-4 shows the projected 2018 NOx emissions from the Phase I and Phase II analyses. In all states that have been updated in this current analysis except Colorado, NOx emissions are seen to decrease relative to the Phase I analysis. This is due to the assumption of fewer wellhead compressors being used in states like Wyoming and Utah, and the improved estimates of drilling time per well in these areas. In Colorado a net increase in NOx emissions is predicted, but this is largely due to the addition of the Southern Ute tribal inventory in 2002, which had not been previously considered, and the subsequent growth of the tribal emissions to 2018.

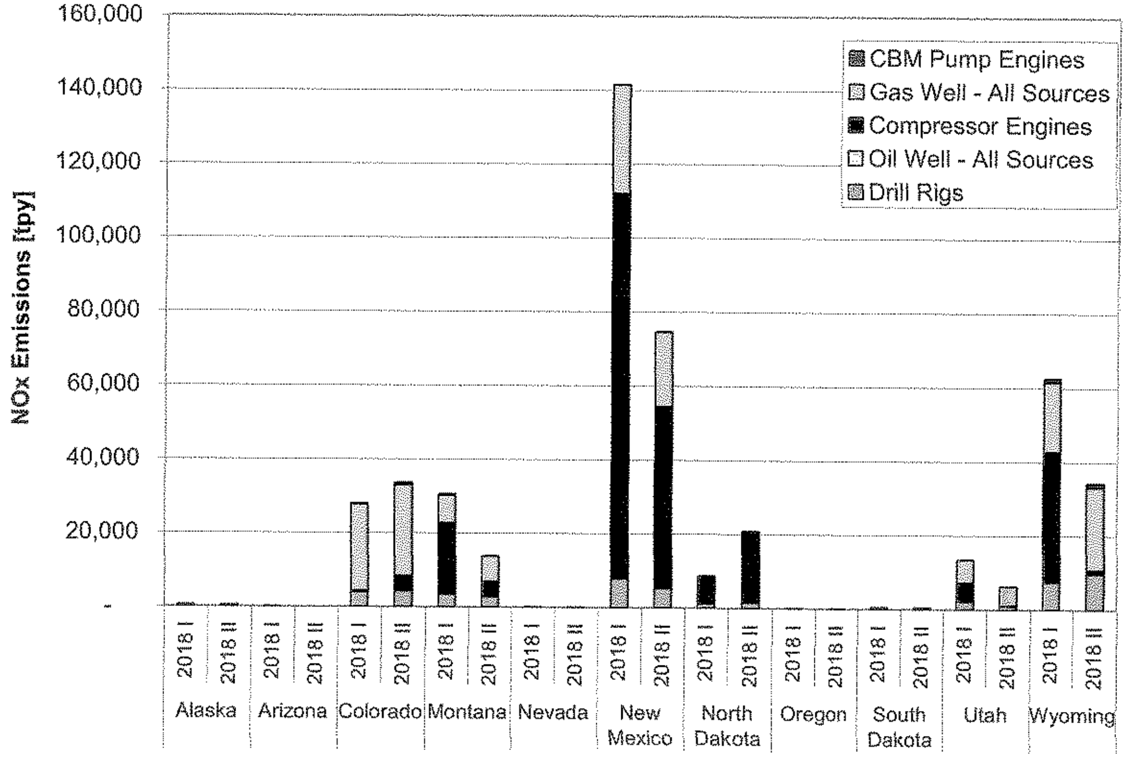


Figure 5-4. 2018 NOx emissions estimates by state in the WRAP region from the Phase I and Phase II analyses.

Figure 5-5 shows the projected 2018 SOx emissions from the Phase I and Phase II analyses. In Utah and Wyoming, there is a significant reduction in SOx emissions relative to the Phase I analysis. This is due largely to an improved estimate of the drilling time, since drilling rigs are the major source of SOx emissions from O&G area sources. In Colorado there is a slight increase in SOx emissions – this is due to the inclusion of the Southern Ute tribal inventory which had not previously been accounted for in Colorado's O&G area source inventory. In New Mexico, the NMED inventory estimated a number of source categories that contribute to SOx emissions but which were not estimated elsewhere in the WRAP region.

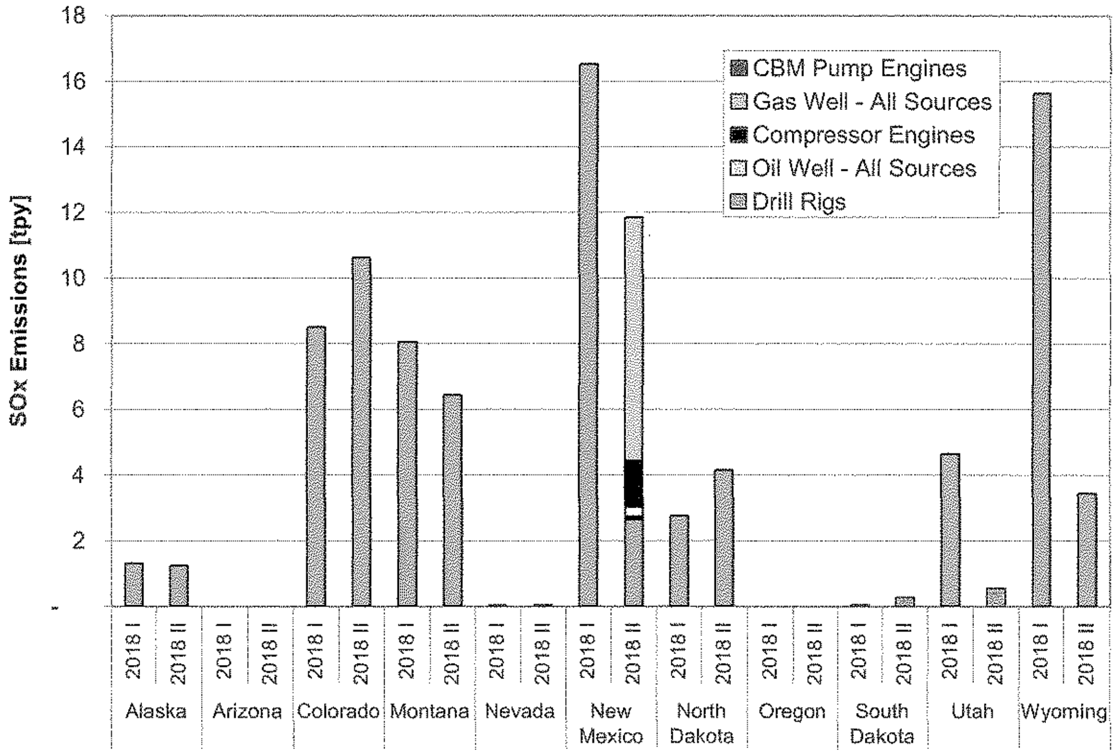


Figure 5-5. 2018 SOx emissions estimates by state in the WRAP region from the Phase I and Phase II analyses.

6. SOx POINT SOURCE PROJECTIONS

An additional task undertaken as part of this analysis was to update projections of SOx emissions from large O&G point sources in the WRAP region in 2018. Previous efforts to estimate 2018 projections of SOx emissions from large gas processing plants and compressor stations in the WRAP region did not take into account potential control technologies being leveraged by gas producers to reduce SOx emissions from these sources. The previous efforts also use Annual Energy Outlook (AEO) factors which did not necessarily reflect accurate growth projections for gas production in 2018, and thus this analysis is tasked with revising these projections.

The methodology employed to revise these projected emissions began with identifying the large natural gas processing plants and compressor stations in the WRAP region that had high SOx emissions. These emissions are generally due to the processing of "sour gas" – that is gas with a significant concentration of H_2S. This was done by accessing the point source database that WRAP had already compiled, which was based largely on information obtained directly from the permitting requirements of the respective state agencies. The list of identified gas plants is listed in Table 6-1.

Table 6-1. Major SOx emitting gas processing plants in the WRAP region.

Plant Name	Plant ID Number	Operator	City	County	State
Brady Gas Plant	5603700008	Anadarko	Rock Springs	Sweetwater	Wyoming
Whitney Canyon Gas Plant	5604100012	BP	Evanston	Uinta	Wyoming
Lost Cabin Gas Plant	5601300028	Burlington	Lysite	Fremont	Wyoming
Carter Creek Gas Plant	5604100009	Chevron	Evanston	Uinta	Wyoming
Beaver Creek Gas Plant	5601300008	Devon (formerly Santa Fe Synder)	Riverton	Fremont	Wyoming
Elk Basin Gas Plant	5602900012	Encore Energy (formerly Howell Petroleum	Powell	Park	Wyoming
Shute Creek Facility	5602300013	Exxon	Kemmerer	Lincoln	Wyoming
Worland Gas Plant	5604300003	Highland Partners	Worland	Washakie	Wyoming
Oregon Basin Gas Plant	5602900007	Marathon Oil	Cody	Park	Wyoming
Dagger Draw Gas Plant	350150285	Agave (formerly Duke Energy)	Artesia	Eddy	New Mexico
Maljamar Gas Plant	350250004	Conoco (formerly Frontier Field Services)	Maljamar	Lea	New Mexico
Denton Gas Plant	350250007	Davis Gas Processing	Lovington	Lea	New Mexico
Artesia Gas Plant	350150011	Duke Energy	Artesia	Eddy	New Mexico
Eunice Gas Plant	350250044	Duke Energy	Eunice	Lea	New Mexico
Linam Ranch Gas Plant	350250035	Duke Energy	Hobbs	Lea	New Mexico
Indian Basin Gas Plant	350150008	Marathon Oil	Carlsbad	Eddy	New Mexico

Plant Name	Plant ID Number	Operator	City	County	State
Jal No. 3 Gas Plant	350250008	Sid Richardson	Jal	Lea	New Mexico
Eunice Gas Plant	350250060	Targa Midstream Services (formerly Dynergy)	Eunice	Lea	New Mexico
Monument Gas Plant	350250061	Targa Midstream Services (formerly Dynergy)	Hobbs	Lea	New Mexico
Saunders Gas Plant	350250063	Targa Midstream Services (formerly Versado Gas Processors)	Lovington	Lea	New Mexico

Title V permits were obtained for all of these sources from the Wyoming Department of Environmental Quality (WYDEQ) and from NMED. These permits contained information on the maximum SOx potential-to-emit from all of these plants, and some indication of whether any control technology was expected to be utilized. In many cases, this information was not available from the permit document, and thus a survey was made of all plant operators in Table 6-1. Survey results indicated that many of these plants either already had in place a control system, or were planning to implement a control system by 2018. The control system most often used was an acid gas injection (AGI) system, which chemically binds to the SOx and converts it to a liquid which is then re-injected into deep wells. Such a system is expected to have an efficiency of 98% in removal of SOx O_2 and this was the control factor assumed for all plants using this technology. Although this technology requires a periodic shut-down and venting of the acid gas, the emissions associated with the shut-down were not accounted for in determining the revised 2018 emissions projections.

In most cases the Title V permits of these plants indicated the potential-to-emit, but not the actual emissions. Actual emissions were reported only if a major change to the plant had been conducted. As part of the survey of plant operators, the actual SOx annual emissions in 2005 were obtained for most plants – for those plants where this information was not obtained, the 2005 emissions were assumed to be identical to the potential-to-emit. In determining the growth factors to apply to each plant, the survey also asked the plant operators to provide information on projected growth in operation of these plants. All plant operators indicated that no growth was expected in gas throughput of these plants and in some instances was expected to decrease. Based on declining production over the past several years, the Whitney Canyon Gas Plant in Wyoming was expected to not be economical to operate by 2018 and therefore based on a regression curve was projected to have zero emissions by 2018. Based on this information, this analysis assumed a no-growth scenario for baseline 2018 emissions. AGI control factors were then applied to the plants that indicated such a system would be in operation by 2018. The results of these projections are shown in Table 6-2.

Table 6-2. Projected 2018 SOx emissions from large point-source gas processing plants in the WRAP region.

Plant Name	Plant ID Number	Operator	State	Previous 2018 SO_2 Emissions [tpy] (Pechan)	Updated 2018 SO_2 Emissions [tpy]
Brady Gas Plant	5603700008	Anadarko	Wyoming	210	181
Whitney Canyon Gas Plant	5604100012	BP	Wyoming	9172	0
Lost Cabin Gas Plant	5601300028	Burlington	Wyoming	3170	2378
Carter Creek Gas Plant	5604100009	Chevron	Wyoming	1184	284
Beaver Creek Gas Plant	5601300008	Devon (formerly Santa Fe Synder)	Wyoming		42
Elk Basin Gas Plant	5602900012	Encore Energy (formerly Howell Petroleum	Wyoming	2136	1500
Shute Creek Facility	5602300013	Exxon	Wyoming	2651	1260
Worland Gas Plant	5604300003	Highland Partners	Wyoming		318
Oregon Basin Gas Plant	5602900007	Marathon Oil	Wyoming	438	350
Dagger Draw Gas Plant	350150285	Agave (formerly Duke Energy)	New Mexico	230	243
Maljamar Gas Plant	350250004	Conoco (formerly Frontier Field Services)	New Mexico	3373	3574
Denton Gas Plant	350250007	Davis Gas Processing	New Mexico	399	295
Artesia Gas Plant	350150011	Duke Energy	New Mexico	1134	19
Eunice Gas Plant	350250044	Duke Energy	New Mexico	953	55
Linam Ranch Gas Plant	350250035	Duke Energy	New Mexico	1261	26
Indian Basin Gas Plant	350150008	Marathon Oil	New Mexico	2794	1100
Jal No. 3 Gas Plant	350250008	Sid Richardson	New Mexico	1633	1231
Eunice Gas Plant	350250060	Targa Midstream Services (formerly Dynergy)	New Mexico		25
Monument Gas Plant	350250061	Targa Midstream Services (formerly Dynergy)	New Mexico	1159	1432
Saunders Gas Plant	350250063	Targa Midstream Services (formerly Versado Gas Processors)	New Mexico		28

7. 2018 EMISSION CONTROL SCENARIOS

The 2018 emissions inventory described in Section 5 of this report, and the control strategies developed in Section 4 of this report, form the basis for a control scenario analysis. The analysis demonstrates a potential scenario in which controls for drilling rigs and compressor engines are applied to the emissions inventory for the San Juan Basin in New Mexico. Some control measures for each of these two source categories are applicable only to certain types of engines. For example lean burn compressor engines are not compatible with non-selective catalytic reduction systems – and thus it is not possible to apply both measures to a single compressor engine. Similarly some drilling rig measures will not apply to the diesel generators that are used on some drilling rigs because these generators do not operate at sufficient load or have a very low maximum horsepower. The exact mix of compressor engines and drilling rigs in the population of this equipment in a particular basin is not known. As described in previous sections, this inventory makes use of basin-wide average assumptions and does not attempt to catalog individual pieces of equipment in use on oil and gas fields in any basin. Thus the exact desired or possible mix of control technologies to be applied to engines in the field is not known.

In light of this limitation, two scenarios are presented here for the San Juan Basin in New Mexico. In the first scenario, conservative assumptions are made about the application of all control measures to the inventory – for drilling rigs there are 7 control measures applied and for compressor engines there are 8 measures applied. Specifically, each of the control measures for compressors and drilling rigs are assumed to apply to 5% of the equipment population. For drill rigs in the San Juan Basin this scenario therefore applies to a total of 35% of all of the rigs operating in the basin, and for compressor engines this scenario applies to 40% of all of the compressor engines operating in the basin. This is a fairly aggressive penetration rate of control technologies, but given the regulations that have been enacted in states like Wyoming, Utah and Colorado, the overall equipment penetration rate is reasonable.

In the second scenario a single example control measure is applied to the emissions inventory for San Juan Basin and is presented to give a tool for quantifying the emissions reductions from a single control measure. In the case of drilling rigs, the example control measure is a selective catalytic reduction system (DRE-2) and for compressor engines it is a combination of an air-fuel ratio controller (CE-2) and non-selective catalytic reduction (CE-1). CE-2 and CE-1 are applied in tandem because a NSCR system typically requires a carefully-controlled air-fuel ratio in the engine to operate at optimal conditions[22].

The emissions reductions for the basin are estimated according to equation 8-1:

$$E_{NOx,red,i} = CF_i \times P_i \times E_{NOx,drillrigs}$$

where $E_{NOx,drillrigs}$ is the NOx emissions from drilling rigs in the basin in tons, P_i is the penetration rate of control measure i in the basin, CF_i is the control factor control measure i in the basin, and $E_{NOx,red,i}$ is the NOx emissions reduction from control measure i applied to drilling rigs in the basin in tons. The costs of applying these control measures to the drilling rigs in the basin are estimated according to equation 8-2:

$$C_{Basin} = \sum_i E_{NOx,red,i} \times CE_i$$

where CE_i is the cost-effectiveness in \$/ton-NOx of control measure i for drilling rigs and C_{Basin} is the total cost of all control measures applied to drilling rigs. Thus this methodology uses the basin total NOx emissions for drillings rigs and the cost-effectiveness of each control measure for drillings rigs to estimate emissions reductions and cost for the basin, and does not require knowledge of the number of drilling rigs operating in the basin. A similar methodology is used for the compressor engines.

Table 7-1 shows NOx emissions reductions only from an example scenario using the 7 drilling rig control measures discussed above in the San Juan Basin, with each control measure applied with a 5% penetration rate. Table 7-2 below shows the associated cost estimates for this example scenario.

Table 7-1. NOx emissions reductions from application of all drilling rig control measures at a 5% penetration rate to the drilling rig NOx emissions inventory for the San Juan Basin.

State	Basin	County FIPS	SCC	NOx Reduction [tpy]	VOC Reduction [tpy]	CO Reduction [tpy]	SOx Reduction [tpy]
New Mexico	San Juan South	35031	2310000220	7	-0.01	0	0
		35039	2310000220	107	-0.55	0	0
		35043	2310000220	0	0.00	0	0
		35045	2310000220	164	-0.81	0	0
		Basin Total		**279**			

Table 7-2. Cost estimates for the entire San Juan Basin from application of all drilling rig control measures at a 5% penetration rate to the drilling rig NOx emissions inventory for this basin.

County	Cost
35031	$170,530
35039	$1,547,020
35043	$4,594
35045	$2,765,373
Total Lifetime Cost	**$4,487,518**

Detailed calculation spreadsheets to estimate emissions control scenarios are provided in Appendix A.

8. CONCLUSIONS AND RECOMMENDATIONS

An analysis of O&G area source emissions has been conducted for the WRAP region, which serves as an update to the previous Phase I effort. This analysis focused on NOx emissions, and specifically on drilling rigs and wellhead compressor engines as large sources of NOx emissions from this activity. NOx and SOx emissions were estimated for 2002, 2005, and projected to 2018 on a basin-wide level, a county level and a state level. The results indicate that significant growth has already occurred in O&G related area source emissions from 2002 to 2005, which largely tracks the tremendous growth in this industry in the western regional U.S. Projections to 2018 show that for some states the growth is projected to continue, but other states that have enacted control measures may begin to see a reduction in NOx emissions from these sources – particularly Wyoming and Utah which have both enacted BACT regulations on O&G area sources. SOx emissions are expected to decrease in 2018 relative to current levels, primarily due to the introduction of low-sulfur diesel fuel as mandated by the EPA. Despite these decreases, O&G area source emissions are expected to continue to be a compliance concern for states in the foreseeable future. Control technologies were identified for many categories of emissions that were determined to be both effective in terms of reducing emissions but also determined to be cost-effective when compared to other measures adopted by State Implementation Plans.

As part of the Phase II inventory process, ENVIRON identified several categories for which more information, or more detailed information, could aid in improving the emissions inventory estimates for the WRAP region.

Drilling rig and compressor engine emissions factors should be obtained for additional pollutants such as VOC, CO, PM and HAPs. This information should be compiled for all engine types. Furthermore, future work should track the maturity of fields to improve estimates of the ratio of wellhead, lateral and central compression being used in particular basins. The same detailed inventory approach that was used for compressors and drilling rigs should be applied to other source categories, such as heaters, well completions, salt-water disposal engines, and CBM pump engines. The focus basins in the Phase II effort should be expanded to include other high activity areas such as Montana, North Dakota, and Alaska.

VOC sources should be inventoried in a future phase of this work. VOCs were not considered a focus of this inventory effort, which largely focused on NOx emissions for regional haze issues. Some major VOC source categories that would need to be examined are flaring, venting/breathing losses, pneumatic devices, glycol dehydrator units, tanks and heaters, and other minor VOC sources. Because a future improved VOC inventory would gather information about losses of natural gas due to venting and breathing, this information would also apply to methane emissions rates – a key greenhouse gas. Similarly, CO_2 emissions should also be estimated in order to obtain a complete greenhouse gas emissions inventory from oil and gas area sources.

More detailed information is the key to improving a region-wide inventory such as this. Future work should include more detailed information from producers, as well as from additional producers. A coordinated effort to contact producers as a group would greatly facilitate this process – indeed the cooperation of the Independent Petroleum Association of the Mountain States (IPAMS) was helpful in obtaining producer information from medium-sized or independent producers as a group. Drilling rig companies should be included in any future survey effort, since much of the drilling is conducted by contracting companies and not by the producers or well owners. This would eliminate the need to use the producers as middle agents to transfer the information about drilling activities.

Similarly any future emissions inventory effort would make use of new and more detailed information from the state OGCs about well counts and production in each state. These OGC databases are frequently updated, even for past years, as more information about wells and production are made available.

New Resource Management Plans (RMPs) and Environment Impact Reports (EIRs) that deal with oil and gas development in the WRAP region are emerging. These should be incorporated into future emissions inventories. Finally, this well-specific information should be utilized to generate new spatial surrogates for allocating these emissions for modeling purposes. Previous spatial surrogates were based on 2002 data, which is reasonable for in-fill activity, but does not capture well any new exploration activity occurring in these regions.

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APPENDIX A

(Available on the WRAP Stationary Sources Joint Forum Oil/Gas Workgroup website:
http://www.wrapair.org/forums/ssjf/documents/eictts/oilgas.html)

Example Controls Scenario for the San Juan Basin, New Mexico

APPENDIX B

Survey Questionnaire for Oil and Gas Producers

Introduction

ENVIRON Corporation, under contract to the Western Regional Air Partnership (WRAP), has been developing estimates of 2002 and 2018 non-point-source (area source) oil and gas (O & G) operations in the WRAP region, which includes the states of Alaska, California, Oregon, Washington, Idaho, Montana, Wyoming, Colorado, Arizona, New Mexico, and North and South Dakota. Emissions estimates derived in Phase I of this work were based on available information from state Oil and Gas Commissions (OGCs), assumptions and estimates of O & G activity in 2002, and projected growth in O & G activity. The Phase I final report on 2002 WRAP regional emissions estimates and projected 2018 emissions estimates can be found at: http://wrapair.org/forums/ssjf/documents/eictts/oilgas.html

After the Phase I WRAP work, ENVIRON prepared a detailed emissions inventory of all oil and gas area source emissions in San Juan and Rio Arriba counties in New Mexico in 2002, under contract to the New Mexico Environment Department (NMED). This emissions inventory was based on a detailed survey of O & G producer activities in the two counties and relied on a high response rate from producers operating in these counties. The final report of the NMED analysis can be found at:
www.nmenv.state.nm.us/aqb/projects/San_Juan_Ozone/NM_Area_Emissions_report.pdf

Based on these two previous analyses, ENVIRON is now engaged in a Phase II updated emissions inventory estimate for the WRAP region for 2002 and updated emissions projections for 2018. In addition, ENVIRON has been asked by WRAP to identify and quantify potential control strategies to reduce these emissions and the potential emissions reductions. The Phase II work will rely on detailed producer information for all basins in which major O & G operations are occurring. Emissions estimates will be made on a well-count basis where possible, and averaged by basin in the WRAP region. A high response rate from producers to this request for information will ensure that this new inventory will be both detailed and accurate.

The purpose of this questionnaire is to assist in the preparation of these updated 2002 and 2018 oil and gas emissions inventories. In this project, we will also be assessing the emission sources that have significant potential for reducing emissions through various control methods and technologies. The potential emissions reductions from the most promising control technologies will be evaluated for each western state and an estimate of the potential reductions in 2018 will be provided.

This document contains a detailed list of questions to producers – by emissions category – that will aid in estimating 2002 and 2018 emissions inventories. This document makes reference to the workplan developed as part of the Phase II work. The workplan document can be found as Attachment I to this questionnaire. The work plan document summarizes the background for developing the updated WRAP emissions inventory and details the methodology and approach that will be taken for each major category of pollutant that we will address. This updated inventory represents a Phase II emissions inventory and seeks to update and make improvements on the Phase I emissions inventory that was conducted previously. The Phase II inventory will rely on more detailed information from producers' on their activities in the WRAP region on a basin-wide average basis as well as information provided by the states.

Overview

The work plan addresses six categories of emissions: drilling rigs; compressor engines; CBM engines; VOC emissions from completion activities, venting and flashing; heaters; and fugitive dust. Except where noted, emissions will be estimated on a count basis, rather than a production basis. This reflects the expected availability of detailed information from producers on their activities in the WRAP region. Count-based data will be averaged within each major basin of significant O & G activity in the WRAP region.

This questionnaire is organized into two sections:

1. Section 1 contains the detailed questions for producers by emissions category
2. Section 2 contains a brief checklist for producers to indicate whether or not the information in Section 1 is available. Section 2 can also be used as a quick reference guide for the information we are requesting.

Where possible, detailed information is requested and it is preferable that this information be provided in electronic form. The information requested for drill rigs and compressor engines, as well as the general questions and questions on projections, are the most important. In order to meet our schedule for completing the WRAP emissions estimates, the deadlines for receiving information are:

1. General questions and questions on drilling rig engines - December 7, 2006
2. Questions on compressor engines and 2018 emissions projections - December 22, 2006
3. All other information - January 10, 2006

We would like to encourage producers to provide information as soon as possible so that we will have sufficient time to conduct a thorough analysis incorporating this information. We are requesting a brief response by November 28, 2006 with whether or not you will be able to provide information on the specific questions included in this questionnaire. Please use the checklist in Section 2 to indicate the availability of information on your operations. Prompt notice of how much data we can or cannot expect in advance of the actual deadline for data transfer will help ensure the best possible analysis is conducted.

ENVIRON will hold confidential all information provided by producers; we will not share specific producer information in response to the operations. We will use the information provided to aggregate and report emissions by field, formation or basin.

All information should be provided in electronic format if possible and preferably in spreadsheet format. All data should be returned to:

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Email: abarilan@environcorp.com

If you have any questions regarding this questionnaire, or any of the questions contained here, please feel free to contact Mr. Bar-Ilan at the phone number or email address above.

SECTION 1

GENERAL QUESTIONS/COMMENTS

Please provide answers to general questions to ENVIRON by December 7, 2006.

Please provide an overview of your Oil and Gas operations in the WRAP region; identify the principal areas of operation and specifically in which basins you have production operations.

In responding to the questions below, please indicate the following for all information that you provide to us:

- **Field, formation or basin to which your information refers**
- **Whether the well, field, formation or basin has conventional or CBM production**
- **Whether the well, field, formation or basin is electrified**
- **Whether the well, field, formation or basin has significant sour gas (H_2S) production**

Please respond to all questions with information from calendar year 2002.

DRILLING RIG EMISSIONS

Please provide answers to questions on Drilling Rig Emissions by December 7, 2006.

1. What are the actual average drilling times (beginning and completion dates) for your drilling operations by formation and by basin in which the formation is located? Please provide either detailed information on drilling times by well, or an average by formation or basin.
2. What are the average drilling depths for your drilling operations by formation and by basin in which the formation is located? Please provide either detailed information on drilling depths by well, or an average by formation or basin.
3. What is the actual load on the drilling rig engine for each well? If this is unavailable, please provide an estimate of the average load of drilling rig engines operating within a formation, or within a basin. Please identify if this load is significantly different if the well is a new well or a workover.
4. What is the average horsepower of drilling rig engines used in your operations in each formation within a basin, or as a basin-wide average? Please identify if the average horsepower of drilling rig engines is significantly different if the well is a new well or a workover.
5. What is the most commonly used make and model (or up to 3 most commonly used makes and models) of drilling rig engines, grouped by horsepower, for each formation or basin in which you drill?
6. What are the manufacturers' rated emissions factors (EFs) for the drilling rig engines identified in Question 5? This should include NOx, CO, VOC, SOx and PM emissions.
7. What type of diesel fuel is used and what is the sulfur content of that diesel fuel for each drilling rig engine by formation, or by basin, or by county, or by state (as appropriate)?

8. Please provide, if possible, information on the total fuel consumption, or fuel consumption rate of drilling rig engines that you operate.
9. What percentage of drilling rig engines in each basin in which you operate use air-assist packages?
10. For those drilling rig engines with air-assist packages identified in Question 9, what is the most commonly used make and model of air compressor used in the air-assist package? What is the average load of that compressor, and what are the manufacturers' rated EFs for that compressor?

COMPRESSOR ENGINE EMISSIONS

Please provide answers to questions on Compressor Engine Emissions by December 22, 2006.

1. How many wells do you operate within each basin in which you operate? Please indicate number of wells and in which basin these wells are located.
2. What fraction of the number of wells in each basin in which you operate use wellhead compressors, what fraction use lateral compressors, and what fraction use centralized compressors? If this information is not available as a fraction of the number of wells, is this information available as a fraction of the total horsepower of compression in each basin in which you operate? If so, please provide the information as a fraction of total horsepower of compression in each basin.
3. What is the average load on a wellhead and/or lateral compressor engine as a basin-wide average for each basin in which you operate?
4. What are the 3 most commonly used makes and models of wellhead and/or lateral compressors in each basin in which you operate?
5. What are the manufacturers' rated emissions factors of NOx, CO, and VOC for each of the makes and models of compressor engines identified in Question 4?

VOC EMISSIONS

Please provide answers to questions on VOC Emissions by January 10, 2007.

Venting of wells occurs frequently to unload fluids that may after time reduce the amount of gas produced. How frequently do you vent wells, and what are the venting flow rates and the amount of time the wells were vented by formation or basin?

Have you taken any measures to reduce venting activity between 2002 and 2005? If so, what is the current frequency of venting at wells averaged by formation or basin?

For NMED, emissions from fugitives were estimated by defining a typical well setup for oil, conventional gas and CBM gas wells. The diagrams for these typical wells are shown in Attachment II of this document. Do these typical well setups adequately represent your operations?

If not, please provide as much detailed information as possible about your typical well setup, including number and type of each item of equipment typically used.

Do you use glycol dehydrators in the field for each basin in which you operate, or are they used only at large central gas plants? If you use glycol dehydrators in the field, please provide information on the number of these units in each basin in which you operate.

What are the emissions rates of your glycol dehydration units?

CBM ENGINE EMISSIONS

Please provide answers to questions on CBM Engine Emissions by January 10, 2007.

What fraction of wells in each basin you operate are CBM wells and what fraction are conventional wells?
For the basins in which you operate that have significant CBM activity, which fuel is used to power CBM engines?
What is the typical activity of the CBM engine (hours per year of operation)? Is the engine running continuously on an annual basis, or for how much time as a basin-wide average?
What is the water production rate from CBM wells that you operate as a basin-wide average?
What is the horsepower of CBM engines as a basin-wide average?
What is the average load of a CBM engine as a basin-wide average? If the CBM engine is fully loaded for a fraction of its total activity time, and lightly loaded as water production decreases, what are these two loads and what fraction of the total activity time is the CBM engine running in each of these modes?
What are the manufacturers' rated or tested EFs for a typical or most commonly used CBM engine?
Are there any emissions control technology installed on a CBM engine and if so what is the effectiveness of these controls for each pollutant (NOx, CO, VOC, SOx, PM)?
What is the fuel consumption rate of CBM engines as a basin-wide average?

HEATER EMISSIONS

Please provide answers to questions on Heater Emissions by January 10, 2007.

1. How many heaters are used at each well site as a basin-wide average for each basin in which you operate? What fraction of all wells within a basin use heaters (for each basin in which you operate)?
2. What is the fuel consumption rate of heaters in the basins in which you operate as a basin-wide average?
3. What is the heat content of the gas used in heaters in each basin in which you operate as a basin-wide average?
4. What is the annual usage of heaters in each basin in which you operate, as number of hours per month for each month? If heaters are operated for some wells in some basins only during winter months, please indicate this.
5. What are the manufacturers' rated EFs for a typical make and model of heater that you operate?
6. What is the sulfur content of the fuel with which the heater operates for each basin in which you operate as a basin-wide average?

FUGITIVE DUST EMISSIONS

Please provide answers to questions on Fugitive Dust Emissions by January 10, 2007.

ENVIRON may conduct an analysis to estimate fugitive dust emissions as part of the Phase II emissions inventory described above. Fugitive dust emissions are defined as re-entrained dust from unpaved roads leading to oil and gas well sites that are serviced by motor vehicles, as part of your O & G operations. Please answer the following questions about fugitive dust following the definition above:

1. Have you ever estimated or reported fugitive road dust emissions from your O & G operations in any basin or state in which you operate? If so, please provide this information.
2. Can you estimate the mileage of unpaved roads leading to well sites as part of your O & G operations in each basin and state? If so, please provide this information.
3. Can you estimate the total vehicle miles traveled (VMT) on unpaved roads leading to well sites of all vehicles that are part of your O & G operations in each basin and state? If so, please provide this information.
4. Can you estimate the average weekly or monthly number of trips on unpaved roads leading to each well site for your O & G operations, and the average miles per trip?
5. What are the typical types of vehicles that travel on unpaved roads to each of your well sites (i.e. van, pickup, truck, etc)?

2018 EMISSIONS PROJECTIONS

Please provide answers to questions on 2018 Emissions Projections by December 22, 2006.

1. For each basin in which you operate, what is the fraction of wells that have wellhead, lateral, and centralized compression for calendar years 2002 and 2005. Can you estimate these same fractions for year 2018 and any or all future years between 2005 and 2018? If this information is not available as a fraction of number of wells, is this information available as a fraction of the total horsepower in each basin in which you operate? If so, please provide this information.
2. What was the estimated average production per well as a basin-wide average in 2002? What was this production per well in 2005? What is the estimated future production per well in calendar year 2018? Please provide information for any future calendar year up to 2018 for which you have an estimate.

SECTION 2

Below is a brief checklist of the information requested in the Section 1 questions. We would like to know whether or not information on each emissions category is available before you begin to answer the questions and provide quantitative information. Please respond to the checklist below and check "Yes" or "No" to whether detailed information is available for each question in each emissions category. If some information is available but not all, please check "Yes". **Please return this completed checklist to ENVIRON by Tuesday, November 28th, 2006.**

Please note that item I – Drilling Rig Emissions, item II – Compressor Engine Emissions, and item VII – 2018 Emissions Projections are the highest priority emissions categories for purposes of this questionnaire. Please reply with information on these emissions categories as soon as possible. All other information may arrive afterwards, but no later than the January 10, 2007 deadline. The dates for specific categories are listed below.

I. Drilling Rig Emissions (due date: December 7, 2006)

	Yes	No
Drilling times		
Drilling depths		
Engine load		
Engine horsepower		
Engine makes/models		
Emissions factors		
Fuel type		
Fuel consumption rate		
Air-assist usage		
Air-assist compressors and compressor emissions factors		

II. Compressor Engine Emissions (due date: December 22, 2006)

	Yes	No
Number of wells by basin		
Fraction of wells with wellhead/lateral/centralized engines by basin		
Fraction of total compression HP that is wellhead/lateral/centralized by basin		
Average load on compressors by basin		
Average makes/models of compressors by basin		
Emissions factors		

III. VOC Emissions (January 10, 2006)

	Yes	No
Frequency of venting at wells		
Venting flow rates		
Venting times		
Recent changes in venting frequency		
Typical well setups		
Glycol dehydrator usage		
Glycol dehydrator emissions rates		

IV. CBM Engine Emissions (due date: January 10, 2006)

	Yes	No
Fraction of CBM wells/conventional wells in each basin		
CBM engine fuel		
CBM engine activity		
Water production rates		
Average horsepower of CBM engines		
Average load of CBM engines		
Emissions factors		
Emissions control technology		
Fuel consumption rate		

V. Heaters (due date: January 10, 2006)

	Yes	No
Number of heaters per well		
Fraction of wells with heaters		
Average fuel consumption rate		
Average heat content of heater fuel		
Annual or monthly activity of heaters		
Emissions factors		
Sulfur content of heater fuel		

VI. Fugitive Dust Emissions (due date: January 10, 2006)

	Yes	No
Estimates or reports on fugitive dust from your operations		
Mileage of unpaved roads leading to well sites		
VMT of vehicles traveling on unpaved roads to well sites		
Average weekly or monthly number of trips to well sites		
Types of vehicles traveling on unpaved roads to well sites		

VII. 2018 Emissions Projections (due date: December 22, 2006)

	Yes	No
Fraction of wells by basin with wellhead/lateral/central compression in 2002		
Fraction of wells by basin with wellhead/lateral/central compression in 2005		
Estimate of fraction of wells with wellhead/lateral/central compression for any calendar year between 2005 and 2018		
Production per well by basin for 2002		
Production per well by basin for 2005		
Estimate of production per well by basin for any calendar year between 2005 and 2018		