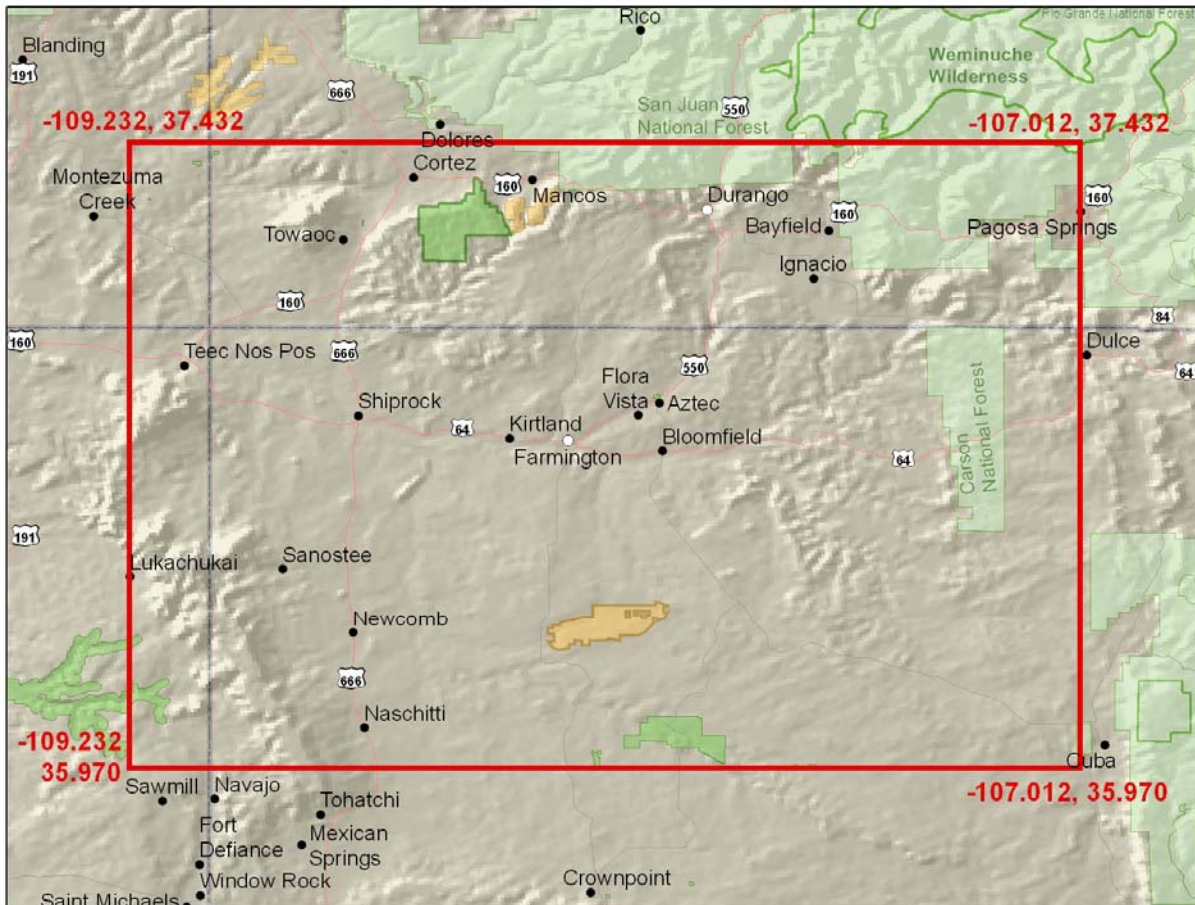


OIL AND GAS SECTION

Four Corners Air Quality Task Force Report of Mitigation Options



November 1, 2007

The report is a compilation of mitigation options drafted by members of the Four Corners Air Quality Task Force. This is not a document to be endorsed by the agencies involved, but rather, a compendium of options for consideration following completion of the Task Force's work in November 2007.

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Oil and Gas: Preface

Overview

The Oil & Gas Work Group of the Four Corners Air Quality Task Force was tasked with analyzing emission mitigation strategies for this industrial sector. For each Mitigation Strategy, and to the extent practicable, the Work Group documented the description of each strategy as well as implementation and feasibility considerations.

Participation in the Oil and Gas Work Group involved state, local and tribal air quality agencies, federal land management agencies, industry representatives, public citizens, and representatives of environmental organizations. Over six working sessions and many monthly conference calls, the work group identified more than 75 potential mitigation strategies. These mitigation strategies were then discussed and either drafted as a mitigation option paper, or eliminated from further analysis where a rationale to do so existed (see Table at the end of this document). The vast majority of the options discussed are represented herein by mitigation option papers for a total of 51.

Organization

The Oil and Gas industry is generally divided into sub-sections according to process. The Work Group used this progression in process to address each stage of the industry, with the exception of exploring Mitigation Options for Engines as a unique section that applies across the processes in the industry. For the purposes of organization and analysis of available Mitigation Strategies, the Oil and Gas portion of the TF Draft Report follows the sequence of definitions as identified below:

1. **Engines:** The work group addressed engines as a separate category in its analysis attributable to all processes in the oil and gas industry. The mitigation strategies were created to address the subcategories of stationary or mobile/non-road engines, drill rig engines, and turbines.
2. **Exploration & Production (E & P):** the work group defined E & P as the upstream sector of the oil and gas industry, including all activities associated with drilling, completion, and putting the well on-line. The work group identified and developed mitigation strategies for specific equipment in E&P, including oil/condensate tanks, dehydrators/separators/heaters, fugitive emissions associated with pneumatic operations, completions, and wellhead considerations.
3. **Midstream:** the work group defined Midstream Operations as occurring after custody transfer, including facilities such as compressor stations, gas processing plants, and transmission or storage of natural gas. Where appropriate, the work group devised mitigation strategies that avoided general overlap with E & P options, and concentrated primarily on options unique to the “midstream operations” that were not otherwise examined in the context of E&P operations.

The Work Group also identified and developed mitigation strategies that address **Overarching** and **Energy Efficiency and Renewable Energy** appropriate for consideration of application to the oil and gas industry.

ENGINES: STATIONARY RICE

Mitigation Option: Industry Collaboration

I. Description of the mitigation option

Overview

- This option explores the possibility of industry collaboration with engine manufacturers to achieve and reliably maintain emissions at or below prescribed levels for upcoming emission standards (i.e., NSPS for engines) on new engines. Such technologies could include but are not limited to lean burn or non-selective catalytic converters (NSCR) with air-to-fuel ratio controllers. The focus on such an effort would be on natural gas fired engines site rated at less than 300 hp.

Air Quality and Environmental Benefits

- This option would result in air quality improvement since all new engines built would meet lowest achievable emission controls at that time for criteria pollutants.
- **Differing opinion:** Reasonably available control technology is the accepted term used by EPA, industry, and regulatory entities versus lowest achievable emission controls that have a different connotation.

Economic

New Engines:

- Depending on the final emission levels established through this effort, operators might have to spend resources ensuring that prescribed emissions limits are being maintained.
- If through this option emission levels are set at levels lower than upcoming federal standards, then detailed engineering/economic analyses should be conducted to examine the incremental cost to control (over the federal regulatory baseline) and to determine if such additional controls are consistent with other programs.

Existing Engines:

- If such a program were expanded to include the retrofitting of all existing engines with current emission control technology, this would require a large capital investment from companies to achieve this result. This would result in replacement of older compressor engines, particularly those less than 200 hp,
- **Differing Opinion:** new engines would be a significant cost to the oil and gas industry. The salvage value of older compressors is a fraction of the cost of a new compressor engine.
- It would require companies to commit to ordering new engines over a prescribed time, likely ahead of when older units would have been replaced.
- The manufacturers would need confirmed orders to justify re-tooling their plants to meet the demand.

Trade-offs

- The use of given emission control technology could result in other emissions. For example, the use of lean-burn technology on a large scale would result in incremental emissions of formaldehyde. If NSCR is used on a large scale, it is believed ammonia emissions would result. However, it is not known if these emissions would be significant.
- Some engine manufacturers that cannot meet the demand and/or re-tool their factories could lose their market share in the San Juan Basin. Need to ensure this does not create any restraint of trade concerns.

II. Description of how to implement

A. Mandatory or voluntary: It could be both. The companies could begin a process of placing new orders voluntarily or the agencies, through regulatory/rules, could require emission levels that necessitate ordering new compressor engines.

Differing opinion: If this is industry collaboration with engine manufacturers, then the regulatory agencies should not expand to rule making that has requirements more stringent than NSPS.

B. Indicate the most appropriate agency(ies) to implement: State Environmental Agencies.

Differing opinion: Not appropriate. If this is industry collaboration with engine manufacturers, then the regulatory agencies should not expand to rule making that has requirements more stringent than NSPS.

III. Feasibility of the option

A. Technical: None identified although some field trials and bench scale tests are probably necessary to assess actual emissions on the new engines.

Differing opinion: EPA has assessed the technological feasibility of controlling these types of engines (See NSPS Mitigation Option Paper below.)

B. Environmental: Yes, from the Cumulative Effects group depending upon what type of emission control technology is preferred. The control technology that will be used will be based on the emission level selected, the lowest cost method of achieving the desired level of emission reduction and the reliability of maintaining emissions at the desired level. Ultimate decisions regarding control options should be based on measurable improvements in ambient air quality.

C. Economic: Economic burdens associated with engine replacement and manufacturer re-tooling are likely to be substantial.

IV. Background data and assumptions used

Emission inventories compiled for the Farmington, NM BLM Resource Management Plan (2003) and Southern Ute Indian Reservation Oil and Gas Environmental Impact Statement (2002).

- Preliminary discussions with companies and engine manufacturer representatives.
- Will need to integrate any more recent emissions inventory data from the Cumulative Effects Group.

V. Any uncertainty associated with the option (Low, Medium, High)

High, especially pertaining to economic feasibility and availability of field proven engines. High due to economics of replacing a large fleet of existing compressor engines and the timing that would be required to begin manufacturing a number of small horsepower engines.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

May need to verify with other work groups if manufacturing a large number of new compressor engines, particularly in the smaller horsepower range, could conflict with other new engine initiatives such as building Tier II and Tier III diesel engines and meeting requirements for additional NSPS general regulations.

Mitigation Option: Install Electric Compression

I. Description of the mitigation option

Overview

- Electric Driven Compression would involve the replacement or retrofit of existing internal combustion engines or proposed new engines with electric motors. Retrofit of internal combustion engines with electric drivers is not generally feasible. Not all compressors can be fitted with an electric motor. This normally requires either a complete package change or, at very least, gear modifications. Electric motors would be designed to deliver equal horsepower to that of internal combustion engines. However, the electric grid capacity in any given area may limit the size/number of electric engines potentially supportable. The reliability of the grid and the easements also must be considered.

Air Quality/Environmental

- Elimination of local emissions of criteria pollutants that occur with the combustion of hydrocarbon fuels (natural gas, diesel, gasoline). Displacement of emissions to power generating sources (utilities) primarily from coal fired power plants (with higher emissions than natural gas fired engines) or natural gas fired peaking units.
- The “emissions balance” for switching to 4-corners grid electricity is illustrated in the table directly below. As apparent, the switch is not necessarily positive when compared with “modern” gas-fired reciprocating engines. The actual “balance” would depend on the particular engine model being compared to an electrical option.

4 Corners Grid Average Emissions lbs/MWh (From NRDC Database) (Average of PNM, Xcel, and Tri-State)	
SO2	3.4
NOx	3.8
CO2	2,473
Caterpillar 3608 LE Average Emissions lbs/MWh (equivalent)	
SO2	0
NOx	2.9
CO2	1,138
Cat. 3608 Assumptions: 9815 Btu/kw-hr "Sweet" Natural Gas NOx - 1 g/hp-hr 1 cu ft gas = 1,000 btu	

See also Cumulative Effects Analysis for this option for further emissions analysis.

Economics

- The costs to replace natural gas fired compressor *engines* with electric motors would be costly. Not all natural gas fired compressors can be fitted directly with an electric motor. This normally requires a complete package change or at very least, gear modifications.

- The costs of getting electrical power to the sites would be extremely high in most cases. It could require a grid pattern upgrade, which could cost millions of dollars for a given area. Maintenance and repair costs associated with the electrical power source are not included.
- A routine connection to a grid with adequate capacity for a small electric motor can be \$18K to \$25K/site on the Colorado side of the San Juan Basin.
- A scaled down substation for electrification of a central compression site can range between \$250K and \$400K.
- Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small.

Tradeoffs

- While the sites where the electrical motors would be placed would not be sources of emissions, indirect emissions from the facilities generating the electricity would still occur such as coal-fired power plants.
- Additional co-generation facilities would likely have to be built in the region to supply the amount of electrical power needed for this option. This would result in additional emissions of criteria pollutants from the combustion of natural gas for turbines typically used for co-generation facilities. Co-generation produces both power and steam; as there is not a market for the steam, this might just be a need for additional power plants or combined cycle plants. Lead time and cost for permitting and new base load generating facilities could be substantial.
- There would need to be possible upgrades in the electrical distribution system. However, the limitation of doing so is predicated by the electrical grid that would exist in a given area to provide the necessary capacity to support electrical compression.
- When comparing emissions from electric generating facilities used to power electric compressors versus natural gas fired compressors, differences in emission rates as well as overall energy efficiency must be examined.

Burdens

- The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry. Extensive capital investments could be required if new generating facilities are needed to meet the electrical demand of this option.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary based on economics of meeting emission reduction requirements and/or initiatives and feasibility of implementation.

B. Indicate the most appropriate agency(ies) to implement: No agency action needed to implement a voluntary program.

III. Feasibility of the option

A. Technical: Feasible depending upon the electrical grid in a given geographic area and overall available electrical power for large-scale conversion in a given geographic area.

B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Indirect emission implications for grid suppliers should be considered (e.g., coal-fired plants).

C. Economic: The economics of implementing this option are much larger than stated above. Considerations such as (but not limited to): 1) cost of energy; 2) electrical demand; 3) reliability; and 4) efficiency need to be included in such an analysis. Costs to control calculations are needed to determine if they are consistent with other options being considered. Modeling needs to be

conducted to evaluate if potentially shifting emissions from natural gas to coal would result in ambient air quality benefits.

IV. Background data and assumptions used

The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff.

V. Any uncertainty associated with the option (Low, Medium, High):

HIGH to MEDIUM based on land accessibility (easements), electric source availability and reliability of uninterrupted supply, advancing GHG legislation/regulation, and economics.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups):

Possibly the Cumulative Effects Group due to indirect emission increases from coal-fired plants. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Install Electric Compression (Alternative - Onsite Generators)

I. Description of the mitigation option

Overview

As an alternative to grid power dedicated on-site natural gas-fired electrical generators can be used to supply power to electric motors that replace the selected RICE compression engines. The electric motors would be rated at an equivalent horsepower to that of RICE engines currently used for gas compression. The power sources for the electric compression could consist of a network of on-site gas-fired electrical power generators. The alternative could be expanded to include consideration of replacement of other engines, such as, gas-fired pump-jack engines used as "prime-movers."

The currently available gas electric generator run on variety of fuels including low fuel landfill gas or bio-gas, pipeline natural and field gases. The gas electric generators are available in the power rating from 11 kW to 4,900 kW. Decisions on the use of on-site generators to replace natural gas-fired engines and the number of generators required would depend on a number of factors, including the proximity, spacing and size of existing engines. As a simple example using the conversion factor of 1 MW = 1,341 HP, adding a 1 MW natural gas-fired generator could replace an inventory of approximately 33 small (40 hp) internal combustion engines if these were reasonably close proximity, say spaced within a one or two mile radius. However, in "real world" operations, there will be several factors involved in determining the number of required gas-fired electrical generators; such as transmission loss, ambient operating temperature, load operating conditions, pattering of applied loads, etc.

Air Quality/Environmental Benefits

The emissions from gas electrical generators are relatively low compare to smaller internal combustion engines because of new technology and ability of controlling emission from big engines. For example a Caterpillar G3612 gas electrical generator with power rating of 2275 kW emits 0.7 gram/hp-hr NO_x at 900 rpm, which is equivalent to 0.0009387 g/W-hr. For comparative illustration with alternative 1, if you assume As stated in the mitigation option; "Control Technology Options for Four Corners Power Plant" (FCPP), the NO_x emission from FCPP is approximately 0.54 g/mmBtu. Based on the assumption that efficiency of FCPP is 40%, the NO_x emission from FCPP is approximately 0.002099 g/W-hr. This comparison shows that the gas electrical generator is more environmentally friendly then using power from a coal based power plant. The baseline average emission for the Western Grid should be used to calculate the real emission difference between installing a lean burn electric generator to replace combustion engines.

The noise from continuously running internal combustion engines can be an issue for the nearby residents. The switch to electric motors will also help cut down the noise in the oil and gas operation.

The need for less maintenance of electric motors and lean burn electric generator will result in fewer maintenance trips for the oil and gas workers which will help in controlling dust as well minimize the impact on wild area in the four corners region.

Economics

The initial capitol cost of installing gas electrical generator and electrical motor would be relatively high. As an example, a generator of 1 MW capacity can approximately support 33 combustion engine of 40 HP. A general purpose 40 HP engines costs about \$ 1200.00 which results in capital cost of \$39,600 for replacing 33 internal combustion engine with electric motors. The approximate cost of a 1.2 MW gas-fired generator is \$430,000. The total capital cost for replacing 33 engines with a gas fired generator will

be about \$470,000. However in long term the benefit in terms of emission reduction and saving in maintenance cost should help in recovering the initial capital cost.

The maintenance cost of one big generator is cheaper than maintenance of many smaller internal combustion engines.

The cost of running electrical wires to connect electric motors will much less than currently installed pipelines to carry natural gas for the small rich burn combustion engines.

Tradeoffs

In case of gas electric generators, there will be shift of emission from many internal combustion engines to one or several big internal combustion engine(s). There would be a net reduction in emissions which will depend on degree of conversion that each producer deems economically feasible.

The cost and affects of running transmission lines from generator(s) to power electrical motors for gas compression needs to be evaluated.

Burdens

The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry.

II. Description of how to implement

- A. Mandatory or voluntary: Voluntary, depending upon the results of monitoring data over time.
- B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies.

III. Feasibility of the option

A. Technical: The feasibility mainly depends on the close proximity of replaceable internal combustion engines and operating conditions of internal combustions engines in order of selection of gas electrical generator. The power, transmission line and substation requirements for on-site lean-burn generator system would need to be carefully considered in deciding the feasibility of this option.

B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Emissions from on-site electric generators would more than off-set the natural gas-fired engines that could be targeted for replacement (e.g., uncontrolled compressor engines or small rich burn pump jack engines).

C. Economic: Depends upon economics of ordering electrical motors, the ability of the grid system to supply the needed capacity and the cost to obtain right of way to drop a line to a potential site. Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small.

IV. Background data and assumptions used

The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff.

Gas electrical generator information was obtained from Caterpillar's Website.

V. Any uncertainty associated with the option (Low, Medium, High):

Medium based upon uncertainties of obtaining electrical easements from landowners and/or land management agencies.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups

Mitigation Option: Optimization/Centralization

I. Description of the mitigation option

Overview

- This option outlines the deployment of internal combustion engines used as the source to power various oil and gas related operations with the appropriate horsepower rated to the need of the activity being conducted. The advantages of this approach would be reducing the cumulative amount of horsepower deployed, which may reduce emissions through elimination of compression and optimization of compressor fleets. This may also be accomplished by using larger central compression in lieu of deploying numerous smaller compressor engines at a number of individual locations such as well sites.
- Overall fleets of engines in the San Juan basin are currently believed to be loaded at about 50% available hp. This is determined by looking at installed hp, volume of gas being moved, and pressure differentials in the field. These load factors are dynamic and constantly changing.
- **Differing opinion:** Emissions from compressor engines are based on the amount of fuel used (a function of capacity and load). Assuming that emission factors do not change with load (this may or may not be true), as the load is reduced emissions will decrease. If it is assumed that all engines have the same rate of emissions, simply reducing the number of engines and operating them at higher capacity will likely result in the same amount of fuel usage and the same amount of emissions. The assumption that all engines have the same emissions is not true and thus this option is based on a flawed premise. In reality, analysis of engine utilization in the region indicates that larger engines have lower emissions than smaller engines.

Air Quality and Environmental Benefits

- The benefits could be lower emissions calculated against horsepower assuming smaller horsepower engines would be deployed to replace larger engines. This would be accomplished by either design or as field conditions changed at individual sites or by centralizing compression horsepower at central site. While efficiency may improve, application of smaller engines working at or near full load may increase NOx emissions relative to an oversized unit operating at reduced load.
- **Differing opinion:** Needs to be framed for applicability to engine type, size, etc.

Economics

- Optimization:
 - The economics of replacing individual site compression with properly sized horsepower could be difficult. Some companies bought individual site compression based upon technical considerations at that time. Unfortunately, due to changing field conditions, which could not be contemplated when the original engine was bought, the existing engine may not be sized properly. To require the purchase of new compressors for changing field conditions over the life of a natural gas field will be an economic strain on the operators.
 - The salvage value of the compressor being replaced is a fraction of a new one.
 - Replacing engine compression several times during the life of well would not be economic. Purchasing new compression with operating conditions in a given field could jeopardize the economics of a well(s).
 - If the engines are rentals, the situation is much more flexible depending upon the lease/contract with the vendor. In the San Juan Basin most smaller well site

compression is a combination of purchased and leased, both of which depend upon the individual operator's preferences.

- Centralization
 - As with optimization, field conditions change and to size equipment properly on a horsepower basis may require numerous iterations of replacement.
 - As above with optimization, the economics of replacing units to fit ever changing field conditions in the cases where the equipment has been purchased will create economic challenges for the operators.
 - For leased units, flexibility would be greater, but would depend upon the lease/contract with the vendor.
 - Use of larger centralized engines increases the opportunity to use low emission lean burn engines.
- Lines and gathering system would probably need to be redesigned and replaced for efficiency, otherwise line losses and bottlenecking could create operation issues. Besides causing increased surface disturbance the economics of line redesign and replacement are probably beyond the economic feasibility limits of the fields in the area.

Tradeoffs

- The tradeoffs for centralization appear to have the most concern.
- There could be an air quality benefit by centralizing, but there would be more long-term surface disturbance involved and dust generation from construction. For instance, a central compressor serving multiple sites would likely need to be built at a new site making it more equitable from an operational perspective to serve its purpose. A new central site would then require surface disturbance for a new site and, whether an existing site could be used or not, underground piping from the central site to multiple sites would be necessary. This could result in permanent new disturbance (if a new site had to be built) and short-term disturbance for the pipeline to multiple sites until this was reclaimed.
- While above ground pipelines are a possibility, for safety reasons these have not been generally used in the San Juan Basin.
- Emissions tradeoffs based on relative operating loads would need to be considered.
- There is potential for increased noise for those living close to these centralized facilities.
- Potential for increased permitting.
- It is possible that centralized compressor stations would become Part 70 or 71 facilities (Title V under the CAA) and would require substantial testing and record keeping on the part of operators and agencies.

Burdens

- The burden for optimization and/or centralization would fall to industry. The cost of pursuing this approach should be carefully considered due to the impact it could have on the economic viability of a given well.
- Increased permitting places burden on regulatory agencies and industry.

II. Description of how to implement

A. Mandatory or voluntary. This option should be voluntary given the economic impacts.

B. Indicate the most appropriate agency(ies) to implement. NA; would be voluntary by the companies since they must assess the technical and economic feasibility.

III. Feasibility of the option

A. Technical: Technical concerns would include trying to size compression properly either with optimization or centralization considering the unknowns associated with changing field conditions.

B. Environmental: Potential environmental benefit would need to be more closely reviewed depending upon the specific scenario. At best, little or marginal benefits are likely to be realized.

C. Economic: While some centralized options could be considered, well-level optimization is not economically feasible considering all the variables that exist with field operations. .

IV. Background data and assumptions used

Discussions with company field and engineering staff

- Input from engine manufacturers and engine consultants

V. Any uncertainty associated with the option (Low, Medium, High)

High. For optimization: The sizing of engines is based on the maximum flow from a well. As wells decline through time the initial hp needs are no longer appropriate. Replacement of this existing hp would be cost prohibitive. For centralization: collection systems are already in place and centralizing would require retrofitting, which is cost prohibitive. Further, in NM, well sites and gathering systems have different owners. Competitors would need to collaborate to centralize, which would be unlikely.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups

None identified at this time. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Follow EPA New Source Performance Standards (NSPS)

I. Description of the mitigation option

EPA is in the process of developing the first national requirements for the control of criteria pollutants from stationary engines. Separate rulemakings are in process for compression-ignition (CI) and spark-ignition (SI) engines. These NSPS will serve as the national requirements, leaving states with the authority to regulate more stringently as might be required in unique situations.

CI NSPS: The final NSPS for stationary CI (diesel) engines was published in the Federal Register on July 11, 2006. It requires that new CI engines built from April 1, 2006, through December 31, 2006, for stationary use meet EPA's nonroad Tier 1 emission requirements. From January 1, 2007, all new CI engines built for stationary use must be certified to the prevailing nonroad standards. (Minor exceptions are beyond the scope of this discussion.)

SI NSPS: The NSPS proposal for stationary SI engines, including those operating on gaseous fuels, was published in the Federal Register on June 12, 2006. Per court order, the rule is to be finalized by December 20, 2007. Like the CI NSPS, certain elements of the SI NSPS will be retroactively effective once finalized. The following summarizes the proposed requirements:

EPA NSPS & APPLICABLE REGULATIONS (40 CFR)		2007		2008		2009		2011	
		1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul
All engines	< 25 hp			40 CFR 90					
Gasoline & RB LPG	26-499 hp			40 CFR 1048					
	> 500 hp		40 CFR 1048						
Natural gas & LB LPG									
Non-emergency	26-499 hp		2.0/4.0/1.0				1.0/2.0/0.7		1.0/2.0/0.7
	≥ 500 hp	2.0/4.0/1.0							
Emergency	> 25 hp			2.0/4.0/1.0					
Landfill / digester gas	< 500 hp		3.0/5.0/1.0					2.0/5.0/1.0	
	≥ 500 hp	3.0/5.0/1.0					2.0/5.0/1.0		

Notes: RB & LB LPG, 26-499 hp, may instead comply with 40 CFR 1048.
 Compliance of all engines with 40 CFR 90 may instead comply with 40 CFR 1048.
 Emergency engines limited to 100 hours per year for maintenance and testing.

All new stationary engines in the Four Corners region will have to meet the new EPA requirements. Deferring to the EPA NSPS will provide the most cost-effective emissions control because manufacturers will have compliant products for sale across much of the country. Compliance with the EPA NSPS will provide a level of emissions control that is federally mandated and will impose a certain financial burden that is not elective. The premise for this mitigation option is that additional control beyond the EPA NSPS would not be needed for new engines.

II. Description of how to implement

A. Mandatory: Compliance with the EPA NSPS will be mandatory. This would apply to all newly manufactured, modified and reconstructed engines after the NSPS effective dates. 'Modified' engines are those undergoing a change that would result in an increase in emissions, while 'reconstructed' engines are those undergoing rebuild work that costs at least 50% of the cost of a new unit. See 40 CFR 60.2 for further definitional details.

Differing Opinion: Voluntary: Applicability of the NSPS requirements could be considered for existing engines. Because a large number of existing engines would require extensive rework or replacement to achieve the NSPS levels, any such approach should be a voluntary, incentive-based program.

B. Indicate the most appropriate agency(ies) to implement: No additional work would be needed other than what EPA is mandating. Any permitting would continue to be at the State's discretion. The

appropriate agencies for any incentive based applicability to existing engines would need to be determined.

III. Feasibility of the option

A. Technical: EPA has spent the past year working with engine manufacturers during its development of the CI and SI NSPS. The requirements have been shown to be technologically feasible.

B. Environmental: EPA's regulatory documents do/will provide details of the expected environmental benefits and the conclusion that this level of control is appropriate for areas not in advanced levels of non-attainment.

C. Economic: EPA's Regulatory Impact Analyses (RIA) for the two rulemakings will provide explanations of the expected costs of compliance.

IV. Background data and assumptions used

None beyond material in EPA's rulemakings.

V. Any uncertainty associated with the option (Low, Medium, High)

Essentially no uncertainty that the NSPS will soon provide new, emissions-controlled stationary engines in the Four Corners region.

VI. Level of agreement within the work group for this mitigation option

The RICE subgroup anticipates Oil & Gas Workgroup consensus that EPA's mandatory compliance with its new NSPS will provide appropriate short- and long-term emissions control that is commensurate with the needs of the Four Corners region.

VII. Cross-over issues to the other source groups

Assistance from Cumulative Effects Work Group needed to assess air quality benefits in the Four Corners area. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Adherence to Manufacturers' Operation and Maintenance Requirements

I. Description of the mitigation option

Engine manufacturers provide to end-users recommended procedures for the initial installation and adjustment of spark-ignition (SI) engines, in addition to on-going preventative maintenance recommendations. Adherence to these recommendations provides long-term, intended performance, emission levels, durability, etc. Please see EPA SI NSPS proposal update below under Section V.

II. Description of how to implement

A. Mandatory or voluntary: While adherence to engine manufacturers' 'recommended' procedures is generally voluntary from a regulatory perspective, this mitigation option instead proposes that such adherence be mandatory. This could be considered for existing engines as well as for new engines. Please see Section V below for further discussion.

B. Indicate the most appropriate agency(ies) to implement: EPA's proposed New Source Performance Standards (NSPS) for, in particular, SI engines, includes several related aspects that will likely be mandatory. Those aspects of engine manufacturers' recommended procedures that are not included in the NSPS could be implemented by the states.

1. 40 CFR 60.4234: **“Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in 60.4233 according to the manufacturer’s written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.”**

2. 40 CFR 60.4241(f): “Manufacturers may certify their engines for operation using gaseous fuels in addition to pipeline-quality natural gas; however, the manufacturer must specify the properties of that fuel and provide testing information showing that the engine will meet the emission standards specified in 60.4231(d) when operating on that fuel. **The manufacturer must also provide instructions for configuring the stationary engine to meet the emission standards on fuels that do not meet the pipeline-quality natural gas definition.** The manufacturer must also provide information to the owner and operator of the certified stationary SI engine regarding the configuration that is most conducive to reduced emissions where the engine will be operated on particular fuels to which the engine is not certified.”

3. 60.4243: **“If you are an owner or operator, you must operate and maintain the stationary SI internal combustion engine and control device according to the manufacturer’s written instructions** or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators of certified engines may only change those settings that are allowed by the manufacturer to ensure compliance with the applicable emission standards. ...The engine must be installed and configured according to the manufacturer’s specifications to ensure compliance with the applicable standards.”

4. 60.4245(a): **“Owners and operators of all stationary SI ICE must keep records of...maintenance conducted on the engine.”**

III. Feasibility of the option

A. Technical: Prudent operators follow manufacturers' recommended procedures. Properly maintained engines operate more efficiently and at lower total cost. Ignition maintenance, in particular, can have significant impact on the performance and life of catalysts.

B. Environmental: Properly maintained engines produce lower emissions. Instead of a fix-as-fail mentality, proper maintenance can avoid or detect failed O₂ sensors or spark plugs, thus avoiding an increase in HC and CO.

C. Economic: The overall, long-term cost of a properly maintained engine is lower than that of a neglected engine.

IV. Background data and assumptions used

V. Any uncertainty associated with the option Medium. EPA NSPS Update: Mandatory requirement to follow engine manufacturers' recommendations is included in the proposal for optionally certified engines. For engines not certified by engine manufacturers, the owner/operator would have compliance responsibility and would not be required to follow the engine manufacturers' recommendations. Owner/operators are raising concern with EPA over the proposed requirement to follow engine manufacturer recommendations for certified engines or follow the proposed option to seek engine manufacturer approval for alternative operational procedures. Many owner/operators believe their own time-proven procedures are appropriate. Because EPA's final rule will have carefully considered the implications of operational and maintenance practices, the Agency's final outcome should be appropriate for new engines used in the Four Corners area. Any consideration of those requirements for existing engines would need to assess the potential benefits achievable through altering current field practices.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups

Mitigation Option: Use of SCR for NOx control on lean burn engines

I. Description of the mitigation option

NOx emissions from lean burn engines (natural gas and diesel fueled) can be reduced by chemically converting NOx into inert compounds. The most effective equipment to achieve NOx reductions is an SCR (selective catalytic reduction) system.

Differing opinion: SCR is one effective equipment option to achieve NOx reductions.

Reactant injection of industrial grade urea, anhydrous ammonia, or aqueous ammonia is required to facilitate the chemical conversion. The overall catalyst reaction is as follows:



The SCR systems utilize programmable logic controller (PLC) based control software for engine mapping/reactant injection requirements. Sampling cells are utilized for closed loop feedback of dosing requirements depending on the amount of NO measured downstream of the catalyst bed.

SCR system components include catalyst housing, housing insulation, control/dosing panel, exhaust dosing/mixing section, and reactant injector. Depending on the reactant medium, a storage tank will be required with a potential minimum temperature requirement of 40°F. **Differing opinion:** Heated reactant storage may drive limited applicability. Description should be expanded to address handling, associated regulations with monitoring and testing for the system slip and RMPs if applicable. Electrical supply to run the SCR system and instrumentation is required.

SCR systems can be constructed with the addition of oxidation catalysts, for the added conversion requirements of CO, VOCs and Formaldehyde. This oxidation catalyst is a dry reaction and is not dependant on injection of a reactant. See the mitigation option on the use of oxidation catalysts for reduction levels achieved for the pollutants.

Differing opinion: Mitigation Option is 'Use of SCR for NOx control on lean burn engines'; therefore, this paragraph may be out of context.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary: May be enhanced by the state supplementing a percentage of the cost.

B. Indicate the most appropriate agency(ies) to implement

III. Feasibility of the option

A. Technical: Dependent on site readiness, installation and start-up would require 7-10 days. **Differing opinion:** Heated reactant storage may drive limited applicability, especially if power is unavailable. Concerns include security risk, handling, safety standards, applicability of RMPs and other associated regulations for monitoring and testing of the system slip. There have been no known applications of this technology for remote unattended oil and gas operations. At the present time there is insufficient information to quantify achievable emission reductions in unattended facilities. The incremental cost to control on lean burn technology is likely to be very high because of the small incremental additional mass reductions as a result of tertiary add on controls. Because SCR uses a dilute aqueous solution, RMP hazards are typically not a concern.

Excessive ammonia slip within a coherent NOx plume may lead to increased NO3 formation. This could result in degradation of visibility even though NOx emissions are reduced.

B. Environmental: Post catalyst NOx levels of <0.15g/bhp-hr.

Differing opinion: <0.15 g/bhp-hr depends on the start point but could imply 95% or greater control. Catalysts optimally start at 90-95% capability but drop over time. Control is sensitive and if it moves off

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set point, result is ‘no’ control (vs. reduced control). What is the origin of the stated NOx levels? On what type of engine in what type of service? This appears to be simply an assertion with no backup or verification.

C. Economic: Cost of SCR system and maintenance are an increased cost to the packager and end user. The five-year cost for SCR on a 3-engine rig in the Jonah/Pinedale area of Wyoming was estimated at \$5 MM in a demonstration pilot conducted by Shell. This information is available from the Wyoming DEQ.

Differing opinion: Costs of heated storage, additional regulatory compliance, added manpower and increased site security would be the burden of the operator. In addition, the engine must be highly stable for this control to be effective (see environmental note).

See also Cumulative Effects Analysis for this option for further emissions analysis.

IV. Background data and assumptions used

V. Any uncertainty associated with the option (Low, Medium, High)

Medium. Negative perception of reactant handling and injection, though the technology has proven itself to be very user friendly.

Differing opinion: HIGH: The assertion that this is “user friendly” technology is not aligned with the experiences documented as part of the pilots noted above. In these pilots, the systems required both a vendor representative and consultant on site to keep them operating correctly. Concerns include heating reactant, security risk, handling, safety standards, applicability of RMPs and other associated regulations for monitoring and testing of the system slip.

Modeling needs to be conducted to evaluate the potential improvement in ambient air quality (ozone, deposition and visibility).

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups (please describe the issue and which groups) None.

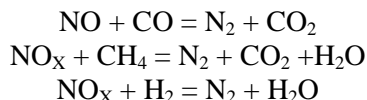
Differing opinion: The CE group needs to offer an opinion on the effect of additional ammonia emissions at plume height.

See also Cumulative Effects Analysis for this option for further emissions analysis.

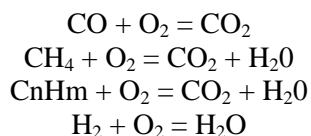
Mitigation Option: Use of NSCR / 3-Way Catalysts and Air/Fuel Ratio Controllers on Rich Burn Stoichiometric Engines

I. Description of the mitigation option, including benefits (air quality, environmental, economic, other) and burdens (on whom, what)

NO_x, CO, HC, and Formaldehyde emissions from a stoichiometric engine can be reduced by chemically converting these pollutants into harmless, naturally occurring compounds of nitrogen, carbon dioxide and water vapor. The most common method for achieving this is through the use of a catalytic converter. In a catalytic converter, the catalyst will either oxidize (oxidation catalyst) a CO or fuel molecule or reduce (reduction catalyst) a NO_x molecule. The general catalyst reactions are as follows:



These reactions are reducing the NO_x to nitrogen and oxidizing the fuel and CO molecules. These reactions oxidize some of the CO and NMHC molecules, however further conversion is accomplished with an oxidizing catalyst. The oxidizing reactions are shown below:



A 3-way catalyst contains both reduction and oxidation catalyst materials and will convert NO_x, CO, and NMHCs to N₂, CO₂, and H₂O. A process which causes reaction of several pollutant components is referred to as a Non Selective Catalyst Reduction (NSCR). NSCR is applicable only on stoichiometric engines. A very narrow air/fuel ratio operating range is necessary to maintain the catalyst efficiency. This can only be consistently maintained by utilizing electronic air/fuel ratio controls.

Maintaining low emissions in a stoichiometric combustion engine using exhaust gas treatment requires a very closely regulated air/fuel ratio. Without an air/fuel ratio controller, emission reduction efficiencies vary through the catalyst. Many Air/Fuel Ratio Controllers (AFRCs) are available on the market today. AFRCs are available from both the engine manufacturer or can be purchased from an after-market supplier. Most controllers utilize closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

Air/Fuel Ratio Control will only maintain an operator-determined set point. For this set point to be at the lowest possible emissions setting an exhaust gas analyzer must be utilized. Operators should utilize quarterly emission tests to ensure units are maintaining compliance.

Differing opinion: This mitigation option is distinct from the mitigation option on using oxidation catalysts on lean burn engines because NSCR controllers are applied only to rich burn engines. Only applies to true rich burn engines, not effective for 1-2% rated rich-burns. 3-way catalysts are only applicable to stoichiometric (true rich burn) engines, potential is to drive the exhaust temperature up. Oxygen, oil slip past engine rings, and poor fuel quality may destroy the catalysts.

II. Description of how to implement

A. Mandatory or voluntary:

Voluntary: May be enhanced by state funding a percentage of the cost.

Mandatory: Mandatory enforcement would give the state the power to eliminate, at the minimum, 90% of NO_x, CO, HC, and Formaldehyde emissions from stationary elements.

Differing Opinion: This option should be mandatory, implemented and enforced by the states.

Differing Opinion: 90% is a reasonable not minimum control for NO_x and CO, but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio. A more likely/achievable reduction of NO_x is in the 80% range and can only be achieved with well operated and maintained engines/AFR's where the load is stable in nature. Variable loads result in less than optimum air/fuel ratios and less reduction.

B. Indicate the most appropriate agency(ies) to implement: States, Tribes and/or BLM, due to the fact that they are already involved in air quality regulations.

Differing opinion: Mandatory implementation of this requirement would only be feasible in a well-crafted permit program administered by the agency having jurisdiction for air quality. BLM does not have regulatory authority for air quality. Although Tribes may have air quality administration authority, very few functional Tribal programs currently exist.

III. Feasibility of the option

A. Technical: Engines can be retrofitted in the field ½ a day or less. Catalysts do have a life span and will lose their efficiencies. However, under ideal operating parameters and with consistent engine maintenance, the life span of a catalyst can easily be up to 5 years. Catalysts can be washed to increase the lifespan in the case of oil spray or ashing. AFRC oxygen sensors should be replaced quarterly to assure constant compliance. Fuel quality limitations are notable, i.e. field gas, biofuel, etc. may damage catalysts.

Differing Opinion: The previous statement is inaccurate; if an engine can be retrofitted, the exhaust system has to be dismantled and rebuilt. Not all engines will accept an after-market add on of AFRC. Usually, the added controls require a new base, piping and if applicable, tear down and modification of protective building/fencing. If the engine is portable/skid mounted, this may prohibit it remaining portable. Retrofit installation of catalyst housings and units typically require additional support structure.

B. Environmental: Minimum of 90% NO_x, CO, HC, and Formaldehyde emission reduction. Some increase in ammonia emissions would result, however, it is not known if this increase would be significant.

Differing opinion: 90% is a reasonable not minimum control for NO_x and CO, but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio. A more likely/achievable reduction of NO_x is in the 80% range and can only be achieved with well operated and maintained engines/AFR's where the load is stable in nature. Variable loads result in less than optimum air/fuel ratios and less reduction. Issues Associated With the Use of NSCR on Existing Small Engines:

- Engines Operate at Reduced Loads and There is a Problem Maintaining Sufficient Stack Temperature for Catalyst to Work
- On Engines with Carburetors, Difficulty Having the AFR Maintain a Proper Setting
- On Older Engines the Linkage and Fuel Control May not Provide "Fine Enough" Control
- If the AFR Drifts Low, NH₃ Will be Formed in Roughly Equal Amounts to NO_x Reduced

C. Economic: The cost of catalyst and AFRC are an added cost to both packager and end user, however, as technologies have advanced, producers have a number of cost effective options. The fact of the matter is the cost to the producer to maintain compliance is much greater than the cost of a catalyst or AFRC. In order to maintain compliance of any kind, the producer is forced to have more manpower, more thorough Oil & Gas: Engines – Stationary RICE

engine maintenance programs, and adequate testing of their units to assure that they are in constant compliance. Caterpillar recommends monthly testing with portable analyzer. See approximate control cost analysis as of January 2007 for an example of the cost of NSCR control.

	<i>NSCR Retrofit Costs</i>		<i>Comments</i>
	<i>Compressco Ford 460</i>	<i>Wauk. 220/330</i>	
<i>Catalyst Housing Purchase</i>	\$2,120	\$1,600	
<i>Catalyst Housing Purchase w/Silencer</i>	\$2,650	\$1,950	
<i>Average Housing Purchase</i>	\$2,385	\$1,775	
<i>Catalyst Element Purchase</i>	\$1,000	\$800	
<i>Air Fuel Ratio Controller Purchase</i>	\$2,950	\$2,950	
<i>"Rebuild" of Fuel and Air Control System on Older Engines</i>			
<i>Electricity for Air Fuel Ratio Controller - Purchase of solar power unit</i>	\$350	\$350	<i>Alternator and Battery or Solar and Battery</i>
<i>Installation of Housing and Catalyst</i>	\$1,080	\$1,080	<i>Assumes one welder and one helper for one full day</i>
<i>Installation/Modification of Support for Housing and Exhaust</i>	\$300	\$300	<i>Estimate of materials - Labor in item above</i>
<i>Installation of Electricity</i>	\$540	\$540	<i>Electrician or Mechanic for 1/2 day - includes travel to and from</i>
<i>Installation and Set-up of Air Fuel Ratio Controller</i>	\$2,160	\$2,160	<i>Electrician or Mechanic and Instrument Technician for one day - includes travel time to and from</i>
<i>Incremental Skid Cost for New Engine</i>	\$1,000	\$1,000	
<i>Taxes, Freight, Etc. (From EPA Manual)</i>	\$1,077	\$1,077	
<i>Total Purchase and Installation - Retrofit</i>	\$11,842	\$11,032	
<i>Total Purchase and Installation - New</i>	\$8,225	\$7,415	
<i>Maintenance Cost</i>			
<i>Quarterly Change of O2 Sensor + Emissions Monitoring - annual cost</i>	\$320	\$320	
<i>Labor/Travel for Above Annualized Catalyst</i>	\$540	\$540	<i>Technician for 1/2 day - includes travel to and from</i>
<i>Replacement (5 yr life)</i>	\$160	\$160	
<i>Total Annual Cost</i>	\$1,020	\$1,020	

IV. Background data and assumptions used

1. G. Sorge "Update on Emissions"

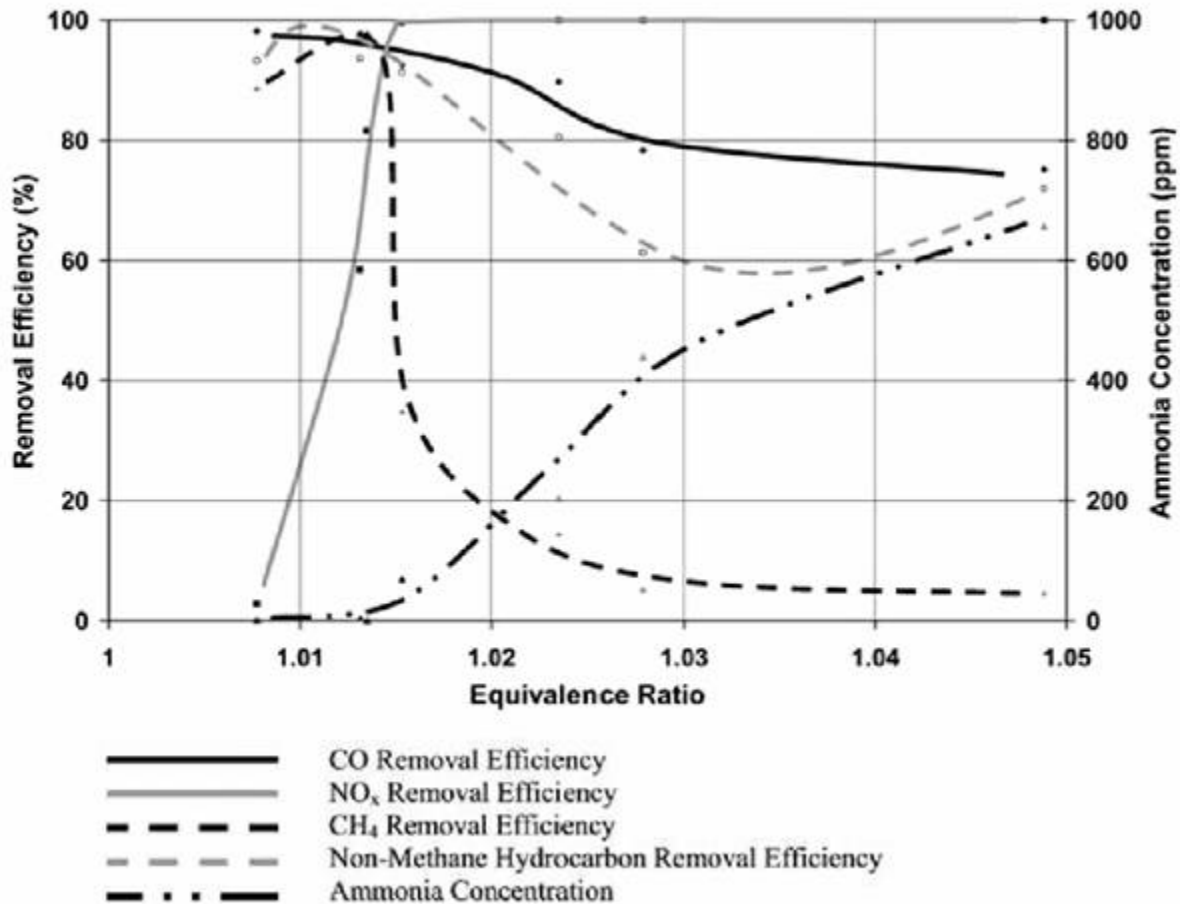
Differing opinion: Insufficient information to locate reference.

V. Any uncertainty associated with the option (Low, Medium, High)

LOW, this is a proven technology with years of results. One issue of merit is the production of ammonia through a 3-way catalyst. This issue has been thoroughly researched and the following are the generalized results:

Differing Opinion: MEDIUM: HC is difficult to measure. Drift of control and narrow applicability to only 'true' rich burn engines are significant issues.

The problem of NH₃ formation across catalyst equipped rich burn CNG engines is associated with problems of the A/F controllers. If the A/F ratio is allowed to drift rich, considerable NH₃ can be formed. This is shown in the following graph:



Differing opinion: Reference is needed for the Graph credentials.

For a variety of reasons the A/F controllers have failed to control at the desired set point, O₂ sensors failing, a not particularly sophisticated controller, etc. Today's AFRCs are very exact machines with the ability to easily maintain a precise set point. If a rich burn engine is operated with a properly functioning

air/fuel ratio controller plus 3-way catalyst, it will meet emissions requirements without producing a noticeable amount of ammonia.

VI. Level of agreement within the work group for this mitigation option TBD

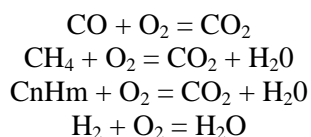
VII. Cross-over issues to the other source groups None at this time.

Differing Opinion: The CE group needs to offer an opinion regarding the impact of increased ammonia emissions in the region. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Use of Oxidation Catalysts and Air/Fuel Ratio Controllers on Lean Burn Engines

I. Description of the mitigation option

CO, HC, and Formaldehyde emissions from a lean burn engine can be reduced by chemically converting these pollutants into harmless, naturally occurring compounds, such as carbon dioxide and water vapor. Lean Burn Engines already have low uncontrolled NO_x emission values (Lean burn engines are a form of NO_x control and therefore do not have uncontrolled emissions). The most common method for achieving this is through the use of a catalytic converter. In a catalytic converter, the oxidation catalyst will oxidize (oxidation catalyst) a CO or fuel molecule. The most common method for achieving CO, HC and formaldehyde control this is through the use of an oxidation catalytic converter. The general oxidizing reactions are shown below:



Air/fuel ratio control helps to maintain the catalyst efficiency. This can only be consistently maintained by utilizing electronic air/fuel ratio controls. However, most air/fuel ratio controllers are utilized to maintain engine performance due to ambient conditions. While it is true that lean burn engines perform better with AFRC units they are not needed for oxidation catalyst performance – the exhaust stream in a lean burn engine has sufficient oxygen under all conditions where the engine will run.

Differing opinion: An electronic air/fuel ratio controller is recommended to help maintain the catalyst efficiency.

Maintaining low emissions in a lean combustion engine using exhaust gas treatment is enhanced by the use of an Air/Fuel Ratio Controller, however, not necessary. Many Air/Fuel Ratio Controllers (AFRCs) are available on the market today, from both the engine manufacture in certain cases and after-market suppliers. Most controllers utilize closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

Air/Fuel Ratio Control will only maintain an operator-determined set point. For this set point to be at the lowest possible emissions setting an exhaust gas analyzer must be utilized. Operators should utilize quarterly emission tests to ensure units are maintaining compliance.

Differing opinion: The preceding two paragraphs seem out of place in the context of oxidation catalyst.

II. Description of how to implement

A. Mandatory or voluntary:

Voluntary: May be enhanced by state funding a percentage of the cost.

Mandatory: Mandatory enforcement would require give the state the power to eliminate, at the minimum, 90% of CO, HC, and Formaldehyde emissions from stationary elements. Lean Burn Engines already have low uncontrolled NO_x emission values.

Differing Opinion: This option should be mandatory, implemented and enforced by the states.

Differing Opinion: 80% CO destruction is a more likely/sustainable reduction for CO and HC's.

Formaldehyde destruction/control is less certain but is lower than CO or HC's.

Differing Opinion: 90% is a reasonable not minimum control for CO; but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio.

B. Indicate the most appropriate agency(ies) to implement: States, Tribes and/or BLM, due to the fact that they are already involved in air quality regulations.

Differing Opinion: BLM is not appropriate since they are not charged with air quality management. This is the role and responsibility of the States or Tribes.

III. Feasibility of the option

A. Technical: Engines can be retrofitted in the field ½ a day or less. Catalysts do have a life span and will lose their efficiencies. However, under ideal operating parameters and with consistent engine maintenance, the life span of a catalyst can easily be up to 5 years. Catalysts can be washed to increase the lifespan in the case of oil spray or ashing. AFRC oxygen sensors should be replaced quarterly to assure constant compliance.

Differing Opinion: The previous sentence should be deleted – it is not applicable to oxidation catalyst.

Differing Opinion: The previous statement is inaccurate; if an engine can be retrofitted, the exhaust system has to be dismantled and rebuilt. Not all engines will accept an after-market add-on of AFRC. Usually, the added controls require a new base, piping and if applicable, tear down and modification of protective building/fencing. If the engine is portable/skid mounted, this may prohibit it remaining portable. Typically, retrofit will require additional support structure for the

B. Environmental: Minimum of 90% CO, HC, and Formaldehyde emission reduction.

Differing Opinion: 90% is a reasonable not minimum control for CO; but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio.

According to the EPA speciate database, the majority of HC emissions from RICE are methane (C1), which is not a regulated pollutant under the Clean Air Act. Methane is unregulated because it does not enter into photochemical reactions that form ozone. Therefore, from a THC or more importantly a VOC perspective, such controls will do little to improve ambient air quality. Realistic modeling analyses that focus on population exposure should be performed to evaluate exposure to formaldehyde. 80% CO and HC reduction is more likely in an operational mode. HCHO destruction is not completely understood but is lower than CO or HC.

C. Economic: The cost of catalyst and AFRC are an added cost to both packager and end user, however, as technologies have advanced, producers have a number of cost effective options. The fact of the matter is the cost to the producer to maintain compliance is much greater than the cost of a catalyst or AFRC. In order to maintain compliance of any kind, the producer is forced to have more manpower, more thorough engine maintenance programs, and adequate testing of their units to assure that they are in constant compliance.

IV. Background data and assumptions used 1. G. Sorge “Update on Emissions”

Differing opinion: Insufficient information to locate reference

V. Any uncertainty associated with the option (Low, Medium, High) LOW, this is a proven technology with years of results.

Differing Opinion: The uncertainty is not in the emission reduction technology. The uncertainty is in the ambient air quality benefits that would be achieved as a result of implementation of this option.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups None at this time. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Install Lean Burn Engines

I. Description of the mitigation option

Using gas fueled (reciprocating) **Lean Burn Engines** as the main prime mover in gas compression and generator set applications in the Four Corners area.

Gas engines are the predominant prime mover used to power gas compressor packages. Gas engines are classified as either Rich Burn or Lean Burn. The industry acknowledges a lean burn engine to have an oxygen level measured at the exhaust outlet of about 7-8%. This typically translates into a NO_x emissions rating of 2 g/bhp-hr or less. This will be federally mandated through NSPS regulations requiring performance at this rating for both Lean Burn and Rich Burn engines. Currently, a large percentage of engines operating in the Four Corners Area that have a capacity of greater than 500 hp use lean burn technology and achieve, on average, a NO_x emission rating of less than 2 g/hp-hr.

Lean burn engines have this lower NO_x rating without using a catalyst or any other form of emissions after-treatment. Some lean burn engine incorporate an Air Fuel Ratio Control installed at the engine manufacturing plant.

Typically lean burn engines have a HP rating above 300 HP. This reflects today's manufacturing emphasis.

The main advantage of using a lean burn is in its capability to offer low emissions without after-treatment. In addition, lean burn engines operate at cooler temperatures and may offer longer life between major repairs.

II. Description of how to implement

A. Voluntary – lower emissions should be the goal. How the operator gets there is his selection and responsibility. In other words, allow an operator to either use a lean burn engine without emissions after-treatment or a rich burn engine with emissions after-treatment to achieve the emissions level needed. It is important to note that the majority of engines greater than 500 hp located on the Southern Ute Reservation where there is no minor source permitting program are lean burn or are low emitting engines as a result of post catalyst treatment. This has been a voluntary effort from the operators.

B. Most appropriate agency to implement: EPA and state air boards.

III. Feasibility of the option

A. Technical: Some states have shown preference to accept engines with lean burn technology over rich burn engines using after-treatment. But as of mid-2006 no engine manufacturers offer the lean burn engine at less than 300 HP. So manufacturers would have to develop a new engine to meet this requirement.

B. Environmental: Study the effect of HAPs formation in lean burn emission and whether further reduction is necessary. There has been extensive testing on HAP emissions from lean burn engines and EPA has established MACT standards for major HAP sources that pertain to RICE. Realistic modeling analyses that focus on population exposure should be performed to evaluate exposure to formaldehyde. The consolidated engine rule for SI engines will require HCHO control.

C. Economic: This is the best economic solution when the power rating is available and the total emissions for all pollutants meet the requirement. Typically this is a more economically viable solution than having a rich burn engine with added controls, catalysts and air to fuel ratio.

IV. Background data and assumptions used

Since there are no known lean burn engines under 300 hp, engine manufacturers may be interested in developing them. The development of these engines may be the most acceptable solution to users, EPA,

and states. The forthcoming NSPS will encourage engine manufacturers to develop lean burn engines under 300 hp.

V. Any uncertainty associated with the option (Low, Medium, High)

The uncertainty is not in the lean burn technology but in the ability to meet the air emission requirement across all hp ratings (from 25 - 425 hp) and the acceptance of the final composition of the exhaust gases (including HAPs).

Manufacturers are not unwilling to create new technologies but there is a risk associated with the types of investment returns on technologies developed for small engines.

VI. Level of agreement within the work group for this mitigation option

Some believe that after-treatment is the best option. This is acceptable to an engine manufacturer but this option adds cost related to the additional equipment needed, permitting and monitoring process. In addition, there is the suspicion that engines with after-treatment may be working out of compliance at any one point.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

A study should be conducted on what would achieve the lowest emissions:

- lean burns with no after-treatment
- lean burns with oxidation catalysts and AFRs
- or rich burns with catalysts and AFRs.

From the results, select the option that produces the lowest emissions.

Mitigation Option: Interim Emissions Recommendations for Stationary RICE

I. Description of the mitigation option

The following mitigation option paper is one of three that were written based on interim recommendations that were developed prior to the convening of the Four Corners Air Quality Task Force. Since the Task Force's work would take 18-24 months to finalize, and during this time oil and gas development could occur at a rapid pace, an Interim Emissions Workgroup made up of state and federal air quality representatives was formed to develop recommendations for emissions control options associated with oil and gas production and transportation. The Task Force includes these recommendations as part of its comprehensive list of mitigation options.

Require a 2 g/bhp-hr limit on engines less than 300 HP:

- May lead to 60 to 80 percent reduction in NO_x.
- Help with visibility impairment in Class I areas in four corners region. Monitoring data at Mesa Verde and Weminuche Class I Areas clearly shows that NO_x (NO₃) is responsible for a very small fraction of visibility impairment. Modeling studies using the EPA CALPUFF model suggest that NO₃ is responsible for visibility impairment in the Class I Areas. There are numerous examples that demonstrate that CALPUFF significantly over estimates NO₃ visibility impairment compared to monitoring data.
- Several manufacturers offer engines that meet this specification, commercially available in two stroke engines only. Four stroke Lean burn engines capable of meeting 2 g/bhp-hr are not yet commercially available in sizes < 300hp.
- NSCR catalytic reduction can be added at reasonable cost. Potential engine durability concerns associated with elevated exhaust temperatures must be addressed when considering reasonable costs of installation of NSCR.
- Ammonia emissions may increase from use of NSCR catalyst.
- Increased ammonia may or may not affect visibility in the region.
- Without implementation, air quality standards may be exceeded.

Require a 1 g/bhp-hr limit on engines larger than 300 HP:

- Lean burn technology is widely available from manufacturers.
 - The lean burn technology will help protect visibility in the region.
 - The NAAQS and PSD increments will be less affected.
 - Deposition of NO_x and related compounds would be reduced
- Differing Opinion:** Analysis of engine quarterly flue gas testing results indicates that, on average, it is possible to achieve an emission limit of 1 g/hp-hr, however, it may not be possible to achieve this emission level on a continuous basis.

II. Description of how to implement

These limits should be mandatory for all new and relocated engines and potentially for existing engines as well. The most appropriate agencies to implement this would be the FLMs and the New Mexico, Colorado and Southern Ute environment departments.

Existing fleet has limited compressors that meet these performance criteria. Based on NMAQ Letter of Instruction dated August 2005, <300 hp compressors must meet 2g/hp-hr. It should be noted that BLM does not have air quality authority to require any particular emissions performance from engines. This should be implemented through a well crafted minor source permit program administered by the air quality agencies.

Implementation Status for this Mitigation Option

BLM in New Mexico is currently requiring compressor engines 300 horsepower or less to have NOx emissions limited to 2 grams per horsepower hour as a Condition of Approval for their Applications for Permit to Drill. Effective August 1, 2005, BLM New Mexico, Farmington Field Office (FFO) started adding to each APD issued on and after this date a Condition of Approval (COA) requiring a limit on NOx emissions if operator placed a compressor on the location. The specific condition language states the following:

This permit is contingent on compliance with the New Mexico Environmental Department, Air Quality Bureau's directive that compressor engines 300 horsepower or less have NOx emissions limited to 2 grams per horsepower hour.

This was based on correspondence received by the NM Air Quality Bureau dated June 3, 2005 and June 5, 2005. The FFO developed the language for the COA, which was reviewed by the NM Air Quality Bureau. The operators are required to comply with this COA regardless of whether it is a newly built compressor or a compressor that they bring in from another location or their ware yard and regardless of when the operators places the compressor on the location (i.e. six months later or two years later etc.).

BLM and USFS permits in the Northern San Juan Basin in Colorado involving new and replacement stationary internal combustion gas field engines require the following emission limits, on an interim basis:

- Emission Control (small gas field engines): All new and replacement internal combustion gas field engines of less than or equal to 300 design-rated horsepower must not emit more than 2 grams of nitrogen oxides (NOx) per horsepower-hour. This requirement does not apply to gas field engines of less than or equal to 40 design-rated horsepower.
- Emission Control (large gas field engines): All new and replacement internal combustion gas field engines greater than 300 design-rated horsepower must not emit more than 1.5 gram of NOx per horsepower-hour.

Interim NOx emission requirements for permits on other BLM and USFS lands in southwestern Colorado have not been established at this time. It is expected that NOx emission requirements will be implemented for these areas in the near future, either as a result of several ongoing planning efforts, or on an interim basis until these planning documents are completed.

Interim NOx emission requirements have not been established for gas field engines on the Southern Ute Indian Reservation at this time. Discussions between the Southern Ute Indian Tribe, State of Colorado Environmental Commission, US EPA Region 8, BLM and BIA are ongoing, and it is expected that NOx emission requirements will be implemented for this area in the near future.

III. Feasibility of the Option

The feasibility of a 2 g/bhp-hr limit has been demonstrated and equipment is commercially available. The economic feasibility is acceptable for new engines since the equipment is somewhat more expensive. Economic feasibility is acceptable for many new engines since the equipment is somewhat more expensive.

Differing Opinion: A number of new and existing engines cannot accept NSCR due to potential durability concerns associated with elevated exhaust temperatures during the needed stoichiometric operation, especially at low or varying loads.

The technical feasibility of a 1 g/bhp-hr limit has been demonstrated in commercial applications. The environmental benefits are significant. New lean burn engines can achieve this emission limit with no add-on controls, and rich burn engines can utilize add-on controls to achieve this limit. The cost is

acceptable given the large amounts of gas being compressed by these engines. **Differing Opinion:** The previous statement is subjective and unsubstantiated without supporting data. Need cost benefit analysis to determine acceptable levels. Only the new generation of lean burn engines are capable of meeting a 1 gram performance and then only with AFRC units and near full load.

IV. Background data and assumptions used

The 2 g/bhp-hr limit is based on existing engine technology in conjunction with an NSCR catalyst. The assumptions are that these engines are more than 40 HP and less than 300 HP and that they are natural gas fueled. Further, these engines would be operated with an air fuel ratio controller. The technology for the 1 g/bhp-hr engines larger than 300 HP in natural gas is well established. Although the technology is well established, it will not be commercially available for all engines until 2010. There are large engines available that have a vendor guarantee of emissions approaching 1 g/hp-hr, however, the issue is maintaining emissions at this level on a continuous basis. The new generation lean burn engines in larger sizes will meet 1 g/bhp-hr performance if equipped with AFRC units and operated near full load.

V. Any uncertainty associated with the option

The uncertainty associated with this option is the potential formation of ammonia emissions as a result of add-on controls. Ammonia emissions could worsen the air quality in the region. (See ammonia monitoring mitigation option paper.)

VI. Level of agreement within the work group for this mitigation option TBD.

Differing Opinion: EPA has proposed a 1.0 g/bhp-hr NO_x limit for new SI engines, \geq 500 hp, built on or after July 1, 2010, and for new SI engines, 26-499 hp, built on or after January 1, 2011. While these potential requirements are not expected to be finalized until December 20, 2007, engine manufacturers have already had to initiate engineering work in anticipation of this 1.0 gram requirement. Although a number of lean-burn engines can meet this requirement now, EPA chose the effective dates based upon the fact that other lean-burn engines need the additional time to meet the standards. Cummins has initiated significant work requiring significant resources to modify those engines to achieve the forthcoming 2.0 g/bhp-hr NO_x standard. Cummins believes that the incremental benefit offered by a potential pull-ahead of the 1.0 gram standard for larger engines versus the EPA requirement for 2.0 grams NO_x soon to be effective followed by the 1.0 gram standard three years later would likely be difficult to justify. Such a pull-ahead, without sound justification, would undermine the substantial work being done by EPA and engine manufacturers in moving toward a national requirement that is to avoid similar, yet different, requirements.

VII. Cross-over issues to the other source groups

The cumulative effects and monitoring groups need to address the concerns with ammonia emissions.

Mitigation Option: Next Generation Stationary RICE Control Technologies – Cooperative Technology Partnerships

This option paper investigates the status of five (1-5) new and/or evolving emissions-control technologies. They are: laser ignition, air-separation membranes, rich-burn engine with three-way catalyst, lean-burn NO_x catalyst, and Homogeneous-Charge Compression-Ignition (HCCI) Engine.

Laser ignition is under development in the laboratory, but it has not reached a point where technology transfer viability can be determined.

Air separation membranes have been demonstrated in the laboratory, but have not been commercially available because the membrane manufacturers do not have the production capacity for the heavy-duty trucking industry. Since stationary engines are a smaller market, there is a high probability that the membrane manufacturers could ramp up production in this area.

Rich-burn engines with three-way catalysts borrow from the well-developed automobile industry. It is applicable to smaller engines for which lean-burn technology is not available.

There are several variations of lean-burn NO_x catalysts, but the one of most interest is the NO_x trap. NO_x traps are being used primarily in European on-road diesel engines, but are expected to become common in the U.S. as low-sulfur fuel becomes available. Applicability to lean-burn natural-gas engines is possible but it will require a fuel reformer to make use of the natural gas as a reductant.

1. Laser Ignition

I. Description of the mitigation option

Overview

Laser ignition replaces the conventional spark plugs with a laser beam that is focused to a point in the combustion chamber. There, the focused, coherent light ionizes the fuel-air mixture to initiate combustion. Applicability is primarily to lean burn engines, although laser ignition could be applied to rich burn engines. Compared to rich-burn engines, lean burn engines, which are significantly more efficient, require much higher ignition voltage with spark plugs, whereas it takes lower ignition energy with laser system.

Advantages of laser ignition compared to spark plugs include: 1. Longer intervals between shutdowns for maintenance because wear of the electrodes is eliminated, 2. More consistent ignition with less misfiring because higher energy is imparted to the ignition kernel, 3. The ability to operate at leaner air-fuel mixtures because higher energy is imparted to the ignition kernel, 4. The ability to operate at higher turbocharger pressure ratio or compression ratio because the laser is not subject to the insulating effect of high-pressure air - air at higher pressure requires a higher voltage to make the spark jump the gap, and, 5. Greater freedom of combustion chamber design because the laser can be focused at the geometric center of the combustion chamber, whereas the spark plug generally ignites the mixture near the boundary of the combustion chamber.

However, laser ignition has some unresolved research issues that must be resolved before it can become commercially available. These include: 1. Lasers are intolerant of vibration that is found in the engine's environment. 2. Some means of transmitting the laser light to each combustion chamber should be developed while accommodating relative motion between the engine and the laser. This might be done with mirrors or with fiber optics. Fiber optics generally lead to a simpler solution to the problem. 3. Current fiber optics is limited in the energy flux they can transmit. This leads to a less-than-optimum energy density at the focal point. 4. Wear of the fiber optic due to vibration may limit its lifetime. 5. The

cost of a laser is such that multiple lasers per engine are too expensive. Therefore, a means of distributing the light beam with the correct timing to each cylinder must be developed.

Air Quality and Environmental Benefits

Although laser ignition could be applied to rich burn engines, environmental benefits would accrue to lean burn engines. Air quality and environmental benefits are difficult to quantify at the current state of development. The more consistent ignition compared to spark ignition can be expected to decrease emissions of unburned hydrocarbons. The ability to operate at leaner air-fuel ratios and at higher turbocharging pressure is expected to decrease emissions of NO_x because of lower combustion temperatures. Laser ignition systems have not been developed to the point where the effect of improved combustion chamber design can be measured. It is reasonable to expect that a better combustion chamber design would further decrease emissions of unburned hydrocarbons, carbon monoxide, and NO_x. In actual operation of the engine, misfiring of one or more cylinders contributes to loss in efficiency and increase in emissions. With the laser ignition system, misfiring can be virtually eliminated. It is estimated that with laser ignited lean burn engines, the regulated levels of California Air Resources Board NO_x levels can be met.

Economic

The primary advantage of laser ignition is its potential to eliminate downtime due to the need to change spark plugs. This advantage would accrue to both rich burn engines and lean burn engines. Higher efficiency due to near elimination of cylinder misfirings is an additional benefit.

Trade-offs

A tradeoff for engine manufacturers, assuming that laser ignition can be developed to the point of commercial feasibility, is whether or not to develop retrofit kits. Retrofits would be expected to take away sales of new engines.

A tradeoff for engine users is whether to continue using spark ignition or to purchase a laser ignition that is initially more expensive but has a future economic benefit.

Another tradeoff for engine users is whether to retrofit laser ignition to an existing engine or to spend more money for a new engine in return for future benefits.

II. Description of how to implement

- A. Mandatory or voluntary: Implementation should be voluntary because the primary incentive for implementation is economic.
- B. Indicate the most appropriate agency(ies) to implement: At the current state of development, a research organization is the best agency to develop laser ignition. After its feasibility is shown, an engine manufacturer, working with an ignition system supplier, is best equipped to carry the development through from product research to a commercial product.

III. Feasibility of the option

- A. Technical: The primary technical risks are whether sufficiently high light flux can be carried through the fiber optic and whether the fiber optic is sufficiently durable. Laser ignition can be retrofitted to engines that use 18-mm spark plugs.
- B. Environmental: If the technical barriers can be overcome, there is little environmental risk to laser ignition.
- C. Economic: If the technical barriers can be overcome, the economic incentive for its adoption will depend on whether the engine must operate continuously or whether downtime can be scheduled to change spark plugs. The requirement for continuous operation favors laser ignition, which is expected to have a higher initial cost than spark ignition, but which can eliminate most of the

downtime for changing spark plugs.

IV. Background data and assumptions used TBD.

V. Any uncertainty associated with the option (Low, Medium, High) Medium to High

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups) TBD

2. Air-Separation Membranes

I. Description of the mitigation option

Overview

The purpose of air-separation membranes is to change the proportion of nitrogen to oxygen in air. A membrane can be optimized to either enrich the oxygen content or to enrich the nitrogen content. Both the oxygen enrichment mode and the nitrogen enrichment mode have been tested in the laboratory with diesel engines. The nitrogen enrichment mode has been tested in the laboratory with Natural Gas Fuel as well. The oxygen enrichment mode and the nitrogen enrichment mode are mutually exclusive.

Oxygen enrichment produces a dramatic reduction in particulate emissions at the expense of increased NOx emissions. However, Poola [***ref Poola paper***] has shown that the effects are non linear such that a small enrichment (1 percentage point or less) produces a significant reduction in particulate emissions with only a small increase in NOx emissions. By retarding the injection timing, one can achieve a reduction in both NOx and particulate emissions. The overall benefits of oxygen enrichment are relatively small, so it will not be considered further.

Nitrogen enrichment produces the same effect on emissions as exhaust-gas recirculation; NOx decreases while particulate emissions increase. Unlike diesel exhaust, the nitrogen enriched air does not contain particulate matter. Manufacturers of heavy-duty diesel engines are concerned that introducing particulate matter from EGR into the engine may cause excessive wear of the piston rings and cylinder liner. Thus, nitrogen enriched air is seen as an alternative to EGR. The published data in natural-gas engines show engine-out NOx reductions of 70% are possible with nitrogen-enriched combustion air. [Biruduganti, et al.]

Air Quality and Environmental Benefits

Oxygen-enriched air has only been demonstrated in the laboratory to be beneficial with one type of engine that is considered obsolete. Although the results are encouraging, further testing with a more modern engine would be necessary to confirm the decrease in both NOx and particulate emissions.

The development of oxygen-depleted air is further along and has been demonstrated as an effective alternative to EGR.

Economic

Use of oxygen-depletion membranes might have a higher initial cost than EGR, but would facilitate a longer interval between overhauls. It will have no adverse impact on engine wear or durability; however, EGR at high levels will have reduced engine durability.

Trade-offs

Engine manufacturers are concerned about the abrasive effects of particulate matter on piston rings and cylinder liners and other deleterious effects of EGR [830.pdf]. For the manufacturer the tradeoff is

between the initial cost of an oxygen depletion membrane versus the higher frequency of overhauls required with EGR.

II. Description of how to implement

- A. Mandatory or voluntary: Implementation should be voluntary because the primary incentive for implementation is economic.
- B. Indicate the most appropriate agency(ies) to implement: The engine manufacturer is the appropriate agency to implement air separation membranes because the primary issue is initial cost versus frequency of overhauls.

III. Feasibility of the option

- A. Technical: The technical feasibility of oxygen-depletion membranes has been demonstrated as an alternative to EGR. The technical feasibility of oxygen-enrichment membranes has only been shown in the laboratory for one type of engine. The technical advantages of nitrogen enrichment with membranes have been demonstrated in the laboratory for natural gas and diesel engines.
- B. Environmental: The environmental benefits of oxygen-depletion membranes are the same as EGR.
- C. Economic: Membrane manufacturers are presently unable to produce enough membranes for widespread implementation of the technology in truck engines. However, the oil and gas industry is a smaller market, which might allow the membrane manufacturers to ramp up their production levels. Because of this situation, the economic feasibility of air-separation membranes is difficult to assess.

IV. Background data and assumptions used

www.enginemanufacturers.org/admin/library/upload/830.pdf

Published technical papers by Argonne National Laboratory and others.

V. Any uncertainty associated with the option (Low, Medium, High)

Low to medium. The technology would receive a "low" uncertainty rating if the availability issue were more settled.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups) TBD

3. Rich-Burn Engine with Three-Way Catalyst

I. Description of the mitigation option

Overview

Rich-burn engines with a three-way catalyst borrow from the well developed automobile technology using the same type of catalyst. Key to efficient operation of the catalyst is maintenance of slightly lean of stoichiometric operation of the engine. Typically the exhaust oxygen content is maintained in a narrow range not exceeding 0.5% by means of an oxygen sensor in the exhaust stream and closed-loop feedback control of the fuel flow. The oxygen content is enough to catalytically oxidize carbon monoxide and unburned hydrocarbons as it chemically reduces NO_x to molecular nitrogen and water. If the engine is operated lean of its desired operating point, NO_x reduction efficiency drops off dramatically. If operation is rich, emissions of carbon monoxide and unburned hydrocarbons increase.

It is commercially available as a retrofit for smaller engines. Larger engines are usually operated in the lean-burn mode.

Air Quality and Environmental Benefits

Air quality benefits would be similar to automobiles, where catalytic converters are universally used with rich burn engines.

Economic

Cost of three-way catalyst systems is considered high, but less than that of SCR with a lean-burn engine.

Trade-offs

For small engines (that is, less than 200 BHP) lean burn technology may not be available. Where there is a choice of rich-burn or lean-burn engines, the lean-burn engines offer better fuel economy and more effective, albeit more expensive, overall emissions control via SCR and oxidation catalysts.

II. Description of how to implement

- A. Mandatory or voluntary: The use of three-way catalysts will be dictated by the stringency of emissions regulations. Three-way catalysts are sufficiently expensive that they are not likely to be adopted voluntarily.
- B. Indicate the most appropriate agency(ies) to implement: U.S. EPA and state agencies

III. Feasibility of the option

- A. Technical: The technology is commercially available and has been proven effective. Rich-burn engines have higher engine-out NO_x emissions, typically about 10-20 g/BHP-hr [830.pdf and reportoct31.doc], than lean-burn engine have. This requires the removal of at least 95% of the NO_x if overall emissions are to be reliably reduced to less than 1 g/BHP-hr.
- B. Environmental: The State of Colorado estimates that a 3-way catalyst can remove 75% of the NO_x, unburned hydrocarbons, and carbon monoxide [reportoct31.doc, although manufacturers of equipment claim that 98-99% of these pollutants are removed.
- C. Economic: The State of Colorado estimates that the cost of retrofitting a three-way catalyst system to a rich-burn engine over 250 BHP is \$35,000 with annual operating costs of \$6,000 [reportoct31.doc].

IV. Background data and assumptions used

<http://apcd.state.co.us/documents/eac/cd2/reportoct31.doc>

www.enginemanufacturers.org/admin/library/upload/830.pdf

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups TBD

4. Lean-Burn NOx Catalyst, Including NOx Trap

I. Description of the mitigation option

Overview

Lean-burn NOx catalysts have been under development for at least two decades in the laboratory with the intent of producing a lower cost alternative to SCR.

Several variants of lean-burn NOx catalysts have been studied: (1) Passive lean-burn NOx catalysts simply pass the exhaust over a catalyst. The difficulty has been low NOx conversion efficiency because the oxygen content of a lean-burn exhaust works against chemical reduction of NOx. Conversion efficiencies of the order of 10% are typical [park.doc].

(2) Active lean-burn NOx catalysts use a fuel as a reductant. The catalyst decomposes the fuel, and the resulting fuel fragments either react with the NOx or oxidize. Methane is much more difficult to decompose than heavier fuels, such as diesel [aardahl.pdf]. A wide range of NOx reduction efficiencies from 40% to more than 80% have been published [park.doc and icengine.pdf]. Variants of active lean-burn catalyst systems may use plasma or a fuel reformer to produce a more effective reductant than neat fuel [aardahl.pdf, 2003_deer_aardahl.pdf, and 80905199.htm].

(3) NOx trap catalysts are a more recent development that has seen some laboratory success. Operation is a two-step cyclic process. In the first stage the NOx trap adsorbs NOx while the engine operates in a lean-burn mode. In the second stage, the engine operates with excess fuel in the exhaust. The fuel decomposes on the catalyst and reduces the NOx to molecular nitrogen and water. When the supply of trapped NOx is exhausted, the system reverts back to first-stage operation. NOx reduction efficiencies in excess of 90% have been published [parks01.pdf]. A sophisticated engine control is required to make this system work.

Air Quality and Environmental Benefits

NOx traps have been proven to be effective and have seen some limited commercial success in Europe. NOx traps are one of the reasons for the dramatic reduction in sulfur content of diesel fuel in the U.S. Fuel-borne sulfur causes permanent poisoning of NOx-trap catalysts. There are doubts regarding the NOx conversion efficiency levels after 1,000 hours or longer use. This should be evaluated, as well as the durability of the equipment.

Active lean-NOx catalysts have seen limited commercial success because they are less effective than NOx traps and are not being considered for on-road diesel engines. Some instances of formation of nitrous oxide (N₂O) rather than complete reduction of NOx have been reported.

Passive Lean-NOx catalysts do not provide enough NOx reduction to be considered viable.

Economic

Costs of retrofitting a lean-burn NOx catalyst are estimated at \$6,500 to \$10,000 per engine [retropotentialtech.htm], \$15,000-\$20,000 including a diesel particulate filter [V2-S4_Final_11-18-05.pdf] for off-road trucks. Estimates are \$10-\$20/BHP for stationary engines [icengine.pdf].

Little information on the cost of NOx-trap catalytic systems was found. The overall complexity of a NOx-trap system is only slightly more than that of a lean-burn NOx catalyst, so costs can be expected to be slightly higher. With methane-burning engines, both active lean-burn NOx catalysts and NOx-trap catalysts require a fuel reformer or other means of dissociating methane. This will add an increment of cost.

Both active lean-NOx technology and NOx-trap technology impose a fuel penalty of 3-7%.

Trade-offs

NOx-trap systems compete with SCR systems. For methane-burning engines, a fuel reformer is required for NOx-trap systems. Fuel reformers are less well developed.

If emissions regulations can tolerate higher NOx emissions, an active lean-burn NOx catalyst might be considered.

I. Description of how to implement

- A. Mandatory or voluntary: The costs of lean-burn NOx catalysts and NOx traps are such that voluntary compliance is unlikely. However, depending on the strictness of the regulations, the user may have a choice of systems.
- B. Indicate the most appropriate agency(ies) to implement: U.S. EPA and state agencies.

II. Feasibility of the option

- A. Technical: NOx-trap systems are proven and commercially available for diesel engines. However, they require low-sulfur diesel fuel (less than 15 ppm) to minimize sulfur poisoning of the catalyst. Active lean-burn catalysts are available, but they have a lower NOx reduction efficiency than NOx-trap systems have. Both the lean-burn NOx catalyst and the NOx trap requires a fuel reformer (which can be a catalyst stage upstream of the NOx catalyst) to operate at full efficiency with natural-gas fueled engine.
- B. Environmental: Lean-burn NOx catalysts and NOx-trap catalysts do not have the ammonia slip issue that SCR systems have, but lean-burn NOx catalysts may only partially reduce some of the NOx to nitrous oxide (N₂O). The NOx reduction efficiency of NOx traps is similar to that of SCR systems (>90%), but active lean-burn NOx catalysts have a lower efficiency (40-80%).
- C. Economic: Lean-burn NOx catalysts and NOx traps have lower costs than SCR and they avoid the need to purchase and maintain a separate reductant. However, both lean-burn NOx catalysts and NOx traps impose a fuel consumption penalty of 3-7%.

III. Background data and assumptions used

Abstract of Caterpillar paper found at www.emsl.pnl.gov/new/emsl2002/abstracts/park.doc.
www.meca.org.galleries/default-file/icengine.pdf
www.energetics.com/meetings/recipe05/pdfs/presentations/aardahl.pdf
www.eere.energy.gov/vehiclesandfuels/pdfs/deer_2003/session10/2003_deer_aardahl.pdf
www.swri.org/epubs/IRD1999/08905199.htm
www.feerc.ornl.gov/publications/parks01.shtml
www.epa.gov/oms/retrofit/retropotentialtech.htm
www.wrapair.org/forums/msf/projects/offroad_diesel_retrofit/V2-S4_Final_11-18-05.pdf

IV. Background data and assumptions used None

V. Any uncertainty associated with the option (Low, Medium, High)

NOx traps have a low uncertainty if they are used with low sulfur diesel fuel. They have a medium uncertainty when used with natural gas because of the need to reform the fuel.

Lean-burn NOx catalysts have a medium uncertainty because they may not be able to meet future emissions regulations.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups

To be determined. The issue of incomplete NOx reduction that leaves some nitrous oxide (N2O) may be moot if active lean-burn NOx catalysts cannot meet future emissions regulations.

5. Homogeneous-Charge Compression-Ignition (HCCI) Engine

I. Description of the mitigation option

Overview

Homogeneous charge compression ignition (HCCI) engines are under development at several laboratories. In these engines a fully mixed charge of air and fuel is compressed until the heat of compression ignites it. The HCCI combustion process is unique since it proceeds uniformly throughout the entire cylinder rather than having a discreet high-temperature flame front as is the case with spark ignition or diesel engines. The low-temperature combustion of HCCI produces extremely low levels of NOx. The challenge of HCCI is in achieving the correct ignition timing, although progress is being made in the laboratories.¹

Only a few experimental measurements of NOx from (HCCI) engines have been reported. The measurements are typically reported as a raw NOx meter measurement in parts per million rather than being converted to grams per horsepower-hour. Dibble reported a baseline measurement of 5 ppm when operated on natural gas.² Green reported NOx emissions from HCCI-like (not true HCCI) combustion of 0.25 g/hp-hr.³ The achievable NOx emission levels are yet to be determined. It is not currently known if HCCI technology can be applied to all engine types and sizes. However, if all reciprocating engines could be converted to HCCI so that the engines produce no more than 0.25 g/hp-hr, then the overall NOx emissions reduction would be 80% in both Colorado and New Mexico using the calculation methodology of the SCR mitigation option.

II. Description of how to implement

- A. Mandatory or voluntary: It is too early to determine whether implementation of this technology will be voluntary or mandatory.
- B. Indicate the most appropriate agencies to implement

III. Feasibility of the option

- A. Technical: HCCI is in the laboratory stage of development.
- B. Environmental: HCCI has the potential of extremely low NOx levels.
- C. Economic: HCCI is not sufficiently developed to have proven economic feasibility.

IV. Background data and assumptions used

1. Bengt Johansson, "Homogeneous-Charge Compression-Ignition: The Future of IC Engines," Lund Institute of Technology at Lund University, undated manuscript.
2. Robert Dibble, et al, "Landfill Gas Fueled HCCI Demonstration System," CA CEC Grant No: PIR-02-003, Markel Engineering Inc.

3. Johney Green, Jr., "Novel Combustion Regimes for Higher Efficiency and Lower Emissions," Oak Ridge National Laboratory, "Brown Bag" Luncheon Series, December 16, 2002.

V. Any uncertainty associated with the option (Low, Medium, or High)

HCCI has high uncertainty.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups (Please describe the issue and which group.)

Summary

Five technologies are reported: laser ignition, air-separation membranes, rich-burn engine with three-way catalyst, lean-burn NOx catalyst, and Homogeneous-Charge Compression-Ignition (HCCI) Engine.

Laser ignition is not presently a commercial product. The impetus for investigating it is the potential to eliminate the need for changing spark plugs. It will also allow operation at leaner air-fuel ratios, higher compression ratios, and higher turbocharging pressure. Leaner air-fuel ratios imply lower engine-out NOx emissions so the after treatment can be smaller or can give lower overall emissions. Higher compression ratios and turbocharging ratios imply higher engine efficiency.

Air-separation membranes used to deplete oxygen from the combustion air can serve as a clean replacement for EGR. That is, an engine using oxygen-depleted air would not be ingesting combustion products. Engine manufacturers are concerned that EGR will shorten the life of their engines and lead to premature overhauls and warranty repairs. The technology has been demonstrated in the laboratory, but has not been used for heavy-duty trucks because membrane manufacturers do not have enough production capacity for the market. Stationary engines are a smaller market, so the membrane manufacturers may be able to ramp up their capacity with stationary engines. Applicability is to diesel engines and rich-burn natural-gas engines. Oxygen-depletion membranes have not been tested with lean-burn natural-gas engines.

A rich-burn engine with a three-way catalyst is a mature technology that is borrowed from automobile engines. The three-way catalyst effectively control NOx, unburned hydrocarbon, and carbon monoxide emissions. It requires an exhaust oxygen sensor with a closed-loop control of the fuel so that exhaust oxygen is maintained in a narrow range not exceeding 0.5%. It can be retrofitted to existing engines and is primarily applicable to small engines for which lean-burn combustion is not available. Its primary disadvantages are cost and the inherently lower efficiency of rich-burn engines compared to lean-burn engines.

Lean-burn NOx catalysts have several forms, but the one that is of most interest is the NOx-trap catalyst. Unlike SCR, lean-burn NOx catalysts use the engine's fuel as a reductant and do not require a separate supply of reductant. It is well proven in the laboratory and is commercially available in Europe for diesel engines, but it requires a fuel reformer if natural gas is used as the reductant. A sophisticated control system is required to cycle the engine between its two modes of operation. Ammonia slippage is not an issue with NOx traps, and if there is any slippage of unburned fuel it can be removed with an oxidation catalyst. Cost is high but less than that of SCR systems. A disadvantage of NOx traps is that they are intolerant of fuel-borne sulfur. For diesel fuel, the sulfur content must be less than 15 ppm. Fuel-borne sulfur permanently poisons the catalyst. Since fuel is used as a reductant, there is a fuel consumption penalty of 3-7%.

ENGINES: MOBILE/NON-ROAD

Mitigation Option: Fugitive Dust Control Plans for Dirt/Gravel Road and Land Clearing

I. Description of the mitigation option

Fugitive dust emissions from traffic on dirt roads and construction sites are a nuisance and cause frequent complaints. Health concerns related to PM 10 (particulate matter less than 10 microns in size) exposure to high concentrations are breathing, aggravated existing respiratory and cardiovascular disease, lung damage, asthma, chronic bronchitis, and other health problems. Adequate measures could include wind breaks and barriers, water or chemical applications, control of vehicle access, vehicle speed restrictions, gravel or surfacing material use, and work stoppage when winds exceed 20 miles per hour. Activities occurring near sensitive and/or populated areas should receive a higher level of preventive planning. Sensitive receptors would include schools, housing, and business areas.

Economic burdens include increase business costs associated with increased road maintenance, loss of time and productivity associated with work stoppage during high wind days, and increased travel times due to speed restrictions. However, reduced wear on roads and vehicles may be recognized through vehicle speed restrictions.

II. Description of how to implement

A. Mandatory or voluntary: Speed restrictions, regular road maintenance, and construction activity restrictions during high wind days would be mandatory. Road surfacing, wind breaks and barriers and vehicle access control would be voluntary.

B. Indicate the most appropriate agency (ies) to implement: The states, tribal governments, BLM, FS, County, and Industry.

III. Feasibility of the option

A. Technical: The current BLM Road committee is a functional working group with 13 road maintenance units. An industry representative is assigned to each unit to oversee road construction and maintenance activities through a cost-sharing program. BLM law enforcement along with county and state law enforcement could enforce speed restrictions. Industry could make observing speed limits a company policy. Conditions of approval could be added to permitted activities to restrict surface disturbing activities during high wind days. However, industry would prefer the use of other mitigation measures such as road surface treatments (e.g. fresh water or special emulsion) during high wind days.

B. Environmental: The environmental benefits from regular and proper road maintenance, speed restrictions, and surface disturbing activities during high wind days are well documented.

C. Economic: Cost sharing is an important purpose of the current roads committee that is very active and functional work group with regularly scheduled meetings. Funding for speed enforcement is an intricate part and regularly funded operation of BLM, county and state law enforcement.

IV. Background data and assumptions used

1. BLM Gold Book-Surface Operating Standards for Oil and Gas Exploration and Development.
2. Numerous studies on road related erosion issues and standards exist.
3. Studies on excessive road speed and dust development.

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option

Four member drafting team support this option

VII. Cross-over issues to the other source groups None at this time.

Mitigation Option: Use Produced Water for Dust Reduction

I. Description of the mitigation option

This option involves using produced water on roads for dust suppression. Large volumes of water are often produced in conjunction with natural gas production, especially coal bed methane (CBM) production. Wells often produce up to 100-400 barrels/day. CBM produced water quality ranges from nearly fresh water to well above 10,000 ppm total dissolved solids (TDS) and is readily available as an option for road dust suppression. The produced water used for dust mitigation would have to have low TDS and low sodium levels that meet BLM and county standards. Some CBM water meets these standards but not all of it.

Economic benefits could be realized by oil and gas operators in reduced trucking and disposal costs. Likewise, there are associated environmental benefits to this reduced trucking as is outlined in another mitigation strategy. However, the use would be as needed and seasonal (during prolonged dry periods or drought).

Environmental concerns and issues would arise concerning 1) salt build up along roadways, 2) migration of water and associated pollutants off the roadway, 3) impacts to vegetations, 4) salt loading to river systems.

Differing Opinion: Produced water in the Four Corners region contains toxins and therefore should not be used for dust mitigation. The potential environmental concerns include more than just salt-related impacts. Produced waters are of variable quality. Depending on the source, the water may contain high concentrations of constituents other than salts. Data on produced water quality is not widely available to the public. One example of produced water quality, however, was published in a recent report prepared with support from the U.S. Department of Energy. The data show that in the New Mexico portion of the San Juan Basin, there can be elevated concentrations of various metals and other constituents in produced water (in addition to elevated salts – those data not shown).¹

	McGrath SWD ²		Four CBM injection wells ³	
	Max	Min	Max	Min
All values in mg/L				
Barium	8.0	0.72	23.9	1.86
Boron	3.0	1.0	2.87	1.6
Bromium	21.8	7.1	15.2	2.4
Copper	0.019	ND		
Chromium	0.035	ND	0.005	
Iron (dissolved)⁴	187	1.1	0.843	0
Selenium	0.080	ND	0.0171	ND

¹ DiFilippo, Michael N. August, 2004. Use of Produced Water in Recirculating Cooling Systems at Power Generating Facilities. Semi-Annual Technical Progress Report October 1, 2003 to March 31, 2004. Report produced with support from U.S. Department of Energy, Award No. DE-FC26-03NT41906. pp. 12-3.

² McGrath Saltwater Disposal Well (SWD): data were from a 30 day random sampling of the SWD well), which was operated by Burlington (now, presumably Conoco).

³ CBM SWD wells operated by Dugan (Salty Dog 2 and 3 Injection Wells) and Richardson (Turk's Toast and Locke Taber Injection Wells).

⁴ According to DiFilippo (page 10), most of the iron comes from aboveground carbon steel pipe used to convey produced water. So, presumably, if water were applied from trucks getting water from the well site, itself, this would not be a concern. If it were water being loaded at the SWD facility, then the iron would be present.

Silver			0.20	ND
Strontium	55	7.2	34.5	1.73
Lead	0.031	ND	0.1	
Total Petroleum Hydrocarbons (TPH)	520	23	17	ND
Zinc			0.298	ND

* ND is non-detected

Produced water may also contain chemical additives put downhole during the drilling, stimulation or workover of the wells. Some of these treatment chemicals, such as biocides, can be lethal to aquatic life at levels as low as 0.1 part per million.⁵ It is very difficult to obtain information on the concentrations of treatment chemicals and additives in produced water.

Environmental Justice Issues: Only with the permission of surface owners, municipalities, counties, etc. should produced water be applied to roads. And these entities should be provided with produced water quality information prior to road spreading.

Wyoming requires landowner consent prior to road spreading, which is an important provision to ensure that surface owners have a say in the application of large quantities of water that could affect their property. In Pennsylvania, other jurisdictions, such as municipalities, also have a say with respect to whether or not road spreading is allowed.⁶

II. Description of how to implement

A. Mandatory or voluntary: The use of produced water would be voluntary; however, ultimate approval to do so would be up to the state authority that has primacy over the disposal and use of produced water.

B. Indicate the most appropriate agency(ies) to implement: OCD, BLM, FS.

It may also be necessary to include the states in the implementation of any permitting process related to road spreading since these agencies have the expertise and develop the environmental standards related to surface and groundwater pollution. There is a precedent for involving environment departments. In Wyoming, although the Oil Conservation Commission is responsible for permitting road spreading applications, the operations must also be approved by their Department of Environmental Quality.⁷

III. Feasibility of option

A. Technical: This option is technically feasible, but would require strict controls and monitoring. “Because of the potential for contaminants from the brine to leach into surface or ground waters, the Department of Environmental Protection (DEP) has developed guidelines that must be followed when spreading brine on unpaved roads.”⁸ It would be advisable for the responsible agencies to develop their

⁵ Argonne National Laboratory. January, 2004. A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas and Coalbed Methane. Prepared for U.S. Department of Energy. Contract No. W-31-109-Eng-38.

⁶ <http://www.dep.state.pa.us/dep/deputate/minres/oilgas/fs1801.htm>

⁷ Rules and Regulations of the Wyoming Oil and Gas Conservation Commission Chapter 4, Section 1 <http://www.cbmcc.vcn.com/dust.htm>

“(nn) Landfarming and landspreading must be approved by the DEQ. Jurisdiction over roadspreading or road application is shared by DEQ and the Commission. . .”

⁸ <http://www.dep.state.pa.us/dep/deputate/minres/oilgas/fs1801.htm>

own guidelines or policies to ensure that road spreading practices are carried out in an environmentally sound manner.

B. Environmental: Would require constraints on the allowable TDS and/or SAR content of the water and volumes applied. Baseline field testing for migration/movement would be required to determine if salt build-up is occurring. The use of boom type sprayer (i.e. spreader bars) to prevent pooling and washing off of roadway needs to be highly considered. A responsible party on site during application would be necessary and signage indicating road maintenance being conducted.

Most jurisdictions that allow road spreading do not require chemical data on anything but the salts or dissolved solids (TDS). While TDS includes constituents such as dissolved metals, it does not provide any specific information as to the concentrations of the various metals. Basing the acceptability of using produced water for road spreading on salt content or TDS overlooks the potential impacts from other produced water constituents like metals, hydrocarbons, treatment chemicals and radionuclides (e.g., strontium).

Prior to application of produced water for road spreading purposes, it would be prudent to analyze the water for all potentially harmful constituents. In 2000, there was a case in Garfield County, CO, where a company illegally spread flowback fluids from a workover operation. Samples of the produced water subsequently showed that TDS levels and BTEX were above state drinking water standards.⁹

Prohibit spreading of flowback water. In Pennsylvania, operators are not allowed to spread produced water that main contain treatment chemicals. “Only production or treated brines may be used. The use of drilling, fracing, or plugging fluids or production brines mixed with well servicing or treatment fluids, except surfactants, is prohibited. Free oil must be separated from the brine before spreading.” Essentially, this would mean that the operator would have to wait a certain period of time to allow the majority of the treatment chemicals to flow out of the well before using the produced water for road spreading purposes.

C. Economic: Some operators may see a reduction in hauling and trucking cost associated using produced water for dust control.

IV. Background data and assumptions used

1. Currently produced water is used in some areas for road reconstruction and maintenance, but not for dust reduction. Current levels allowed are 5,000 TDS for maintenance and 18,000 TDS for reconstruction.
2. Could consider higher TDS levels of use with tight restriction on applications methods and timing.
3. Assume applications would be seasonal (during summer dry months)
4. Restricted to main collector road or on all roads with high traffic flow.
5. Need to protect operator’s investment for roadwork already completed.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium uncertainty to environment (water quality and vegetation).

VI. Level of agreement within the work group for this mitigation option.

All members of drafting team support this option.

VII. Cross-over issues to other source groups None at this time.

⁹ Colorado Oil and Gas Information System. 7/6/2000. Notice of Alleged Violation Report. Barrett Resourced Corp. Document No. 850224. http://oil-gas.state.co.us/cogis/NOAVReport.asp?doc_num=850224

Mitigation Option: Pave Roads to Mitigate Dust

I. Description of the mitigation option

This option involves paving roads that service the vast amounts of oil and gas locations in the four corners region. The benefits to air quality would be a significant reduction in dust generated by traffic in the San Juan Basin. Consideration should be given to paving only those collector roads that are located near populated areas and those that received heavy traffic and excessive dust because of high cost of paving. Currently a pilot project is being proposed to use hot emulsified asphalt on reconstructed collector roads. The hot asphalt would be incorporating it into the sandstone caps material using a road re-claimer or blade in an effort to create a durable driving surface.

Economic burdens would be extreme costs to oil and gas operators, federal, state and local governments associated with paving and maintaining a vast network of roads in the San Juan Basin. There would be an immediate increase in traffic accidents associated with an eminent increase in speed associated with paved roads.

II. Description of how to implement

A. Mandatory or voluntary: The construction and road base preparation necessary to properly pave a road would be voluntary

B. Indicate the most appropriate agency(ies) to implement: Industry, OCD, BLM, FS, County, State.

III. Feasibility of option

A. Technical: This option is technically feasible but not practical to pave all roads. Consideration needs to be given to highly travel collector roads and road near heavily populated areas. Portions of heavily travel roads could be considered for paving.

B. Environmental: Would reduce long term dust emissions from vehicle traffic throughout the San Juan Basin but there would be some shorter term increases in emissions associated with asphalt production, paving, and the construction equipment paving the road itself. However, increase accidents and speeding could be drawbacks. Additional law enforcement would be required or re-prioritized workload to curtail speeding.

C. Economic: The cost to prepare, pave, and maintain roads throughout the San Juan Basin are not practical on all roads. Furthermore, the cost to reclaim "paved roads" as part of the restoration process upon well abandonment would be substantial. Consideration could be give to paving only portions of main collector roads, especially in populated areas with heavy traffic.

IV. Background data and assumptions used

1. Pilot project currently proposed. Need to evaluate the effectiveness of using hot emulsified asphalt. Not practical to pave all roads in the San Juan Basin.
2. Restricted to main collector road with heavy traffic, dust problems, and populated areas.
3. Would require addition capital outlay and cost sharing.

V. Any uncertainty associated with the option (Low, Medium, High)

High, due to cost and feasibility.

VI. Level of agreement within the work group for this mitigation option.

Members agree that this option has some merit but in limited areas. Not practical to consider the entire San Juan Basin.

VII. Cross-over issues to other source groups None at this time.

Mitigation Option: Automation of Wells to Reduce Truck Traffic

I. Description of the mitigation option

This mitigation option would involve equipping wells with a variety of technology for the ultimate purpose of being able to decrease traffic to well sites when everything is operating normally. The potential air quality benefits include reduced dust and tailpipe emissions from vehicle traffic. Other potential environmental benefits include reduced vehicular fuel consumption (and therefore the need for crude oil feedstocks). Economically, the energy companies could benefit by reducing their workforces and the expenses paid for contractors. As this automation may require the electrification of the equipment, the air quality benefits may be offset by emissions elsewhere and of a different nature. Costs for implementing this option may entail the installation of massive electrification systems to power the sensors, radios, and automated valves (vista issues). Additionally, should every well not be checked on a daily basis, there is believed to be a high likelihood that leaks small enough to be undetectable by the automation sensors could go on unabated until the next time the well was visited. This would represent a real tradeoff of risk (air quality vs. soil / water impact). Significant burden would fall on the operator in such a situation. An additional benefit of this option is that once electricity is available at the site, it would increase the feasibility of the electric compressor option included under Stationary RICE.

II. Description of how to implement

The oil & gas industry already uses automation technology where technically and economically feasible. Therefore, this mitigation option would best be implemented in a voluntary manner. As such, agency involvement would not be required.

III. Feasibility of the option

A. Technical: The technology exists today to implement this mitigation option.

B. Environmental: A study would need to be made to determine the relative benefit of reducing emissions at the well site but increasing emissions during electrification and offsite power generation. (Cumulative Effects Work Group task?)

C. Economic: In some cases the implementation of this technology is economically feasible. In many others it is not. Forced implementation could very well hasten the uneconomic status of a well resulting in the premature abandonment of the well and its hydrocarbon products.

IV. Background data and assumptions used

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations, hence the high-level and qualitative analysis. (Cumulative Effects Work Group task?)

V. Any uncertainty associated with the option

High. The feasibility of implementing this option is very situation specific. It is believed that widespread implementation (75% of wells) is probably not feasible.

VI. Level of agreement within the work group for this mitigation option

Subgroup is in agreement with this option.

Cross-over issues to the other source groups

None at this time.

Mitigation Option: Reduced Vehicular Dust Production by Enforcing Speed Limits

I. Description of the mitigation option

This mitigation option would involve enforcing speed limits on unpaved roads in an attempt to reduce dust emissions. The potential air quality benefits include reduced dust emissions from slowed vehicle traffic. Another potential environmental benefit (albeit marginal) is reduced vehicular fuel consumption (and therefore the need for crude oil feedstocks). Economically, although theoretically less work would be accomplished in the same time period, this impact would be insignificant since the degree of excess over the speed limit is probably not such that implementation of this mitigation strategy would make a significant difference.

A. Public Roads: Enforcement on public roads would be most easily accomplished using local law enforcement agencies. Costs for stepping up enforcement of the speed limits on public roads might include additional funds for increased staff for the local law enforcement agencies.

B. Private Roads: To the extent the unpaved roads are private, the setting and enforcing of speed limits would have to take place in a cooperative agreement between local landowners and energy companies. Since energy companies are not staffed, trained or equipped to be law enforcement agents, this would represent a significant cost shift to the energy companies. Costs for implementing this option on private roads would entail legal review to understand on what basis such "private law enforcement" could take place, the negotiating of agreements with landowners, the posting of signs, and the staffing, training, and equipping of workers to fulfill this function.

C. Assistance: Cumulative Effects work group would be needed to understand the relative benefit of reduced speed on dust production.

II. Description of how to implement

A. On public unpaved roads, enforcement of existing speed limits could be seen as mandatory. The most appropriate agencies to implement are the existing local law enforcement agencies.

B. On private roads, implementation would have to be voluntary as no agency can force a landowner to undertake such a proposition. It is not appropriate for any agencies to get involved in the implementation of this mitigation option. It would be most appropriate for the environmental agencies to simply recognize this as a bona fide emission reduction strategy, and then let the energy company determine where and when to implement such a strategy.

III. Feasibility of the option

A. Technical – Greater enforcement of speed limits on public unpaved roads would be feasible. Establishing and enforcing speed limits on private unpaved roads is feasible but less so.

B. Environmental - Assistance from the Cumulative Effects work group would be needed to understand the relative benefit of reduced speed on dust production (how much reduction in speed is needed to have a significant reduction of dust?).

C. Economic - Assistance from the Cumulative Effects work group would be needed to understand the relative economic benefit of reduced speed on dust production.

D. Public Perception – This could be an issue based on the assumption that most people would want any additional funding for police activities to go toward safety/crime issues.

IV. Background data and assumptions used

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis in this option paper. The governing equations do however include speed as a component.

V. Any uncertainty associated with the option

High. Assistance from the Cumulative Effects work group would be needed to understand the relative economic benefit of reduced speed on dust production. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups

It is believed that this issue will cross-over to the Other Sources group.

Could the issue described in IV above be addressed by the Cumulative Effects work group?

Mitigation Option: Reduced Truck Traffic by Centralizing Produced Water Storage Facilities

I. Description of the mitigation option

This mitigation option would involve reducing vehicular traffic on unpaved roads (and hence dust production) by centralizing produced water storage facilities and pumping water to them. Much of the large truck traffic on unpaved lease roads is water haulers. Therefore, one strategy to reduce dust is to reduce water hauler traffic. However, unless the produced water could be piped directly to the disposal (injection well) location, the same volume of truck traffic would exist. Therefore, to reap the benefits from this strategy, it would be necessary to either pipe the water directly to the disposal location, or to site the centralized produced water storage facility along a paved road such that the water transporters would not be driving on unpaved roads and creating dust.

Benefits from this strategy include dust reduction, vehicle tailpipe exhaust emission reduction (potential), reduced road maintenance, and marginally safer roads. Burdens would fall exclusively on the energy companies. These burdens would include obtaining rights-of-way to lay the needed pipelines, securing the pipe, securing trenching and installation services, and paying crews to make the necessary tie-ins. As much of the produced water in southern Colorado is essentially fresh in nature, heat tracing may be needed to prevent the freezing and bursting of pipes.

Tradeoffs would include the pollutants emitted at the source of the power used to drive the transfer pumps. This power production could be either at the well location (natural gas fired) or at the power plant (electric). Additionally, the dust emissions are currently dispersed over a large area. Centralizing storage would greatly increase tailpipe emissions locally and potentially produce local air quality, noise, and traffic safety issues. Additionally, aggregating produced water in one location increases the potential for a catastrophic release. This would represent a real tradeoff of risk (air quality vs. soil / water impact). Additional tradeoffs include the emissions produced at the point of pipe manufacture and the emissions from the trenching operations. Assistance is needed from the Cumulative Effects work group to estimate the net air quality gain from centralizing produced water storage facilities.

II. Description of how to implement

- A. This mitigation option should be implemented on a voluntary basis. Forced implementation could hasten the uneconomic status of groups of wells resulting in premature abandonment of the wells and their hydrocarbon products.
- B. The most appropriate agency to implement would be the environmental agency through permitting incentives/offsets. It would be necessary to first understand the relative benefit of reducing emissions from lease road traffic but increasing emissions elsewhere (Cumulative Effects Work Group task).

III. Feasibility of the option

A. Technical: The technology exists today to implement this mitigation option.

B. Environmental: A study would need to be made to determine the relative benefit of reducing emissions from lease road traffic but increasing emissions elsewhere (Cumulative Effects Work Group task).

C. Economic: In some cases the implementation of this technology will be economically feasible. In many others it will not be.

IV. Background data and assumptions used:

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis. This could be a Cumulative Effects Work Group task.

V. Any uncertainty associated with the option (Low, Medium, High):

High. Assistance from the Cumulative Effects work group would be needed to understand the relative economic benefit of reduced truck traffic vs. laying miles of pipelines and setting many pumps. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

V. Cross-over issues to the other source groups

It is believed that this issue will not cross-over to any other source work group. Assistance from the Cumulative Effects work group on the issue in V. above would be helpful.

Mitigation Option: Reduced Vehicular Dust Production by Covering Lease Roads with Rock or Gravel

I. Description of the mitigation option

This mitigation option would involve reducing vehicular dust production by covering unpaved roads with rock or gravel. Benefits from this strategy include only dust reduction. Burdens would fall exclusively on the energy companies. These burdens would include obtaining the road material and paying crews to install it. Additionally, the presence of rock on the roads makes snow removal more difficult, and is hard on snow removal equipment. Therefore, road maintenance costs may increase during the winter months. Tradeoffs would include the pollutants emitted during the trucking and installation of the road material. Assistance is needed from the Cumulative Effects work group to estimate the net air quality gain from centralizing produced water storage facilities.

II. Description of how to implement

A. This mitigation option should be implemented on a voluntary basis. Forced implementation could hasten the uneconomic status of groups of wells resulting in premature abandonment of the wells and their hydrocarbon products.

B. The most appropriate agency to implement would be the environmental agency through permitting incentives/offsets. It would be necessary to first understand the relative environmental benefit of covering roads with rock (Cumulative Effects Work Group task).

III. Feasibility of the option

Technical – The technology exists today to implement this mitigation option.

Environmental – A study would need to be made to determine the relative emission reductions due to covering the roads with rock (Cumulative Effects Work Group task).

Economic – In some cases the implementation of this technology will be economically feasible. In others it will not be.

IV. Background data and assumptions used

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis. (Cumulative Effects Work Group task?)

V. Any uncertainty associated with the option (Low, Medium, High)

High. Assistance from the Cumulative Effects work group would be needed to understand the relative emission reduction benefit from covering lease roads with rock. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups (please describe the issue and which groups

It is believed that this issue may cross-over to the Other Sources work group.

Mitigation Option: Reduced Truck Traffic by Efficiently Routing Produced Water Disposal Trucks

I. Description of the mitigation option

This mitigation option would involve setting up a produced water hauler coordinating / dispatch service to route water haulers as efficiently as possible in order to reducing vehicular traffic on unpaved roads (and hence dust production). Much of the large truck traffic on unpaved lease roads is water haulers.

Therefore, one strategy to reduce dust is to minimize water hauler traffic. To accomplish this goal, it would be necessary institute a central dispatch concept among all of the water haulers in the area such that (a) only full truckloads are hauled from a given area and (b) the water is hauled to the closest disposal facility possible. Benefits from this strategy include dust reduction, vehicle tailpipe exhaust emission reduction, and reduced vehicular fuel consumption (and therefore the need for crude oil feedstocks). Burdens would fall both on the water hauling service companies and on the water disposal companies. These burdens would include agreements to cooperate (which would include the setting of prices), the purchase of compatible radio equipment, and the implementation of a central dispatch facility. There would be no tradeoffs associated with this strategy. Assistance is needed from the Cumulative Effects work group to estimate the net air quality gain from optimizing produced water hauling routes.

II. Description of how to implement

This mitigation option could be implemented on a mandatory basis. In order to set fair prices on water hauling and disposal (like taxi cabs), it would be necessary to involve other agencies and potentially special legislation.

The most appropriate agency to implement would be the states' regulatory entity for the oil and gas industry. It would be necessary to first understand the relative benefit of reducing emissions from lease road traffic due to optimization (Cumulative Effects Work Group task).

III. Feasibility of the option

Technical – The technology exists today to implement this mitigation option.

Environmental – A study would need to be made to determine the relative benefit of reducing emissions from lease road traffic due to optimization (Cumulative Effects Work Group task).

Economic – Implementation of this technology should be economically feasible.

IV. Background data and assumptions used

No input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis. This could be a Cumulative Effects Work Group task.

V. Any uncertainty associated with the option (Low, Medium, High)

Low. Assistance from the Cumulative Effects work group would be needed to understand the relative environmental benefit of optimized truck traffic. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups (please describe the issue and which groups

It is believed that this issue will not cross-over to any other source work group.

Mitigation Option: Use Alternative Fuels and Maximize Fuel Efficiency to Control Combustion Engine Emissions

I. Description of the mitigation option

This option involves the implementation of alternative fuels, ultra low sulfur diesel (15 ppm) and improved fuel efficiency for heavy-duty trucks (Class 7 – GVW 26,001 to 33,001). The air quality benefits include potential reduction of sulfur, greenhouse gases and aromatic compounds throughout the region. Other environmental impacts include a reduction in petroleum consumption and conservation of natural resources.

Economic burdens include the cost of the new alternative fuel/fuel efficient vehicle and cost and availability of the fuel.

There would not be adverse environmental justice issues associated with the implementation of alternative fuels. There is potential for air quality improvements from travels through socio-economically disadvantaged communities with improved fuel efficiency.

Low sulfur diesel can continue to be used in 2006 and older highway vehicles until 2010. Any new 2007 model year highway diesel vehicle will be required to use ultra low sulfur diesel (ULSD). ULSD must be available at retail by October 15, 2006. Terminals should be turned over to ULSD by the end of July. They could consider using ULSD for the non-road equipment too and get even more reductions in PM as well.

II. Description of how to implement

A. Mandatory or voluntary: There may be some mandatory upgrades for new heavy-duty trucks purchased after a set date. The immediate move to alternative fuel vehicles should be a voluntary program and could be incorporated into the San Juan Vistas or similar program. Likewise the states could adopt tax advantaged strategies under a voluntary program to encourage the adoption of alternative fuels.

B. Indicate the most appropriate agency(ies) to implement: NM Dept. of Transportation, Colorado Dept. of Transportation, Federal Highway Administration.

III. Feasibility of the option

A. Technical: Oil and gas industry have developed a diesel fuel made from natural gas through the Fischer-Tropsch (F-T) process, there are other synthetic liquid fuels and major heavy-duty diesel engine companies are working on engines with reduced NO_x and particulate emissions.

B. Environmental: The environmental benefits would primarily be associated with reduced consumption of petroleum resources.

C. Economic: The market will have to drive economically viable alternatives. According to referenced studies, Class 7 Heavy Duty Vehicles use a smaller percentage of fuel than Class 8 trucks (long-haul tractor- trailers), Class 2b vehicles (light trucks) or Class 6 vehicles (delivery vans).

IV. Background data and assumptions used

1. Life Cycle Analysis for Heavy Vehicles by Argonne National Laboratory Transportation Technology R&D Center.
2. Heavy Vehicle Technology and Fuels September 2004 – Argonne National Laboratories Transportation Technology R&D Center.
3. Green Machines facts and figures associated with fuel type, consumption rates, and emissions factors (reference)

V. Any uncertainty associated with the option High.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to other source groups None at this time.

Mitigation Option: Utilize Exhaust Emission Control Devices for Combustion Engine Emission Controls

I. Description of the mitigation option

This option involves the implementation of exhaust emission control devices for heavy-duty trucks (Class 7 – GVW 26,001 to 33,001) such as diesel oxidation catalysts (DOC), diesel particulate filters and/or traps. The air quality benefits include potential reduction of particulate matter and NO_x throughout the region.

Economic burdens include the cost associated with the installation and maintenance of the exhaust emission control devices.

There would not be environmental justice issues associated with the implementation of emission controls.

II. Description of how to implement

A. Mandatory or voluntary: There may be some mandatory upgrades for new heavy-duty trucks purchased after a set date. The immediate move to emission controls should be a voluntary program and could be incorporated into the San Juan Vistas or similar program.

B. Indicate the most appropriate agency(ies) to implement: The states.

III. Feasibility of the option

A. Technical: Technology exists.

B. Environmental: The environmental benefits would primarily be associated with reduced particulates and NO_x.

Most devices are also effective at reducing VOCs, and therefore air toxics and ozone. In fact, the most common, inexpensive, and most demonstrated technologies are oxidation catalysts, which are more effective at removing VOCs than PM and NO_x. After treatment technologies for reducing NO_x (especially on mobile engines) are still evolving, and so strategies for reducing NO_x typically rely on fuel emulsifiers, engine modifications/repair, and engine replacements.

C. Economic: The market will have to drive economically viable alternatives. According to referenced studies, Class 7 Heavy Duty Vehicles use a smaller percentage of fuel than Class 8 trucks (long-haul tractor-trailers), Class 2b vehicles (light trucks) or Class 6 vehicles (delivery vans).

IV. Background data and assumptions used

1. Life Cycle Analysis for Heavy Vehicles by Argonne National Laboratory Transportation Technology R&D Center.
2. Heavy Vehicle Technology and Fuels September 2004 – Argonne National Laboratories Transportation Technology R&D Center.
3. US EPA Clean Diesel and Trucks Rule
4. Green Machines facts and figures associated with fuel type, consumption rates, and emissions factors (reference)

V. Any uncertainty associated with the option (Low, Medium, High) High

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to other source groups

Mitigation Option: Exhaust Engine Testing for Combustion Engine Emission Controls

I. Description of the mitigation option

This option involves the implementation of an inspection and maintenance program to determine if emission controls and engines are functioning properly resulting in reduced emissions. Compliance with the standards set in the 2000 Heavy Duty Highway Clean Diesel Trucks and Buses Rule can be tested with an inspections and maintenance testing program. Environmental benefits include potential reduction of sulfur, NOx and particulates throughout the region.

Economic burdens include the cost of the inspection program, equipment, inspectors, and mobile or stationary inspection facilities.

There would not be environmental justice issues associated with the implementation of exhaust engine testing.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory participation would be required.

B. Indicate the most appropriate agency(ies) to implement: NM Dept. of Transportation, Colorado Dept. of Transportation, Federal Highway Administration.

III. Feasibility of the option

A. Technical: Numerous states currently use exhaust emission testing. Details on mobile inspection programs are widely available.

B. Environmental: The environmental benefits would primarily be associated with reduced sulfur, particulates and compliance with Clean Diesel Trucks Rule.

Most devices are also effective at reducing VOCs, and therefore air toxics and ozone. In fact, the most common, inexpensive, and most demonstrated technologies are oxidation catalysts, which are more effective at removing VOCs than PM and NOx. After treatment technologies for reducing NOx (especially on mobile engines) are still evolving, and so strategies for reducing NOx typically rely on fuel emulsifiers, engine modifications/repair, and engine replacements.

C. Economic: The market will have to drive economically viable alternatives. According to referenced studies, Class 7 Heavy Duty Vehicles use a smaller percentage of fuel than Class 8 trucks (long-haul tractor-trailers), Class 2b vehicles (light trucks) or Class 6 vehicles (delivery vans).

IV. Background data and assumptions used

1. Life Cycle Analysis for Heavy Vehicles by Argonne National Laboratory Transportation Technology R&D Center.
2. Heavy Vehicle Technology and Fuels September 2004 – Argonne National Laboratories Transportation Technology R&D Center.
3. US EPA Clean Diesel and Trucks Rule
4. Green Machines facts and figures associated with fuel type, consumption rates, and emissions factors (reference)

V. Any uncertainty associated with the option (Low, Medium, High) Medium

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to other source groups None at this time.

Mitigation Option: Reduce Trucking Traffic in the Four Corners Region

I. Description of the mitigation option

This option involves implementing various measures to reduce the mileage required to truck fluids or equipment for oil and gas exploration, production, or treating operations. The air quality benefits include increased operating efficiency by 10% which will equate to 10% reduced fuel usage, which results in a net reduction of emissions of NO_x by [] tons per day, SO_x by [] tons per day, a reduction in greenhouse gas emissions of [] and PM_{2.5} emissions by [] tons per day. Other environmental impacts include reduced dust and noise from the trucks and roads at nearby residences, and reduced unintentional killing of wildlife and livestock that may be killed truck traffic.

Economic burdens include the cost of centralized facilities and systems designed to maximize routing efficiency, which may be partially offset by the benefits to human health of improved air quality and reduction of highway traffic (and traffic accidents) in the region.

There should not be any environmental justice issues associated with the placement of the centralized tank batteries (including produced water tanks, condensate tanks and/or crude oil tanks) in socio-economically disadvantaged communities.

Differing opinion: There are potential health hazards associated with crude oil and condensate tank emissions. Concentrating these facilities in socio-economically disadvantaged communities is an example of environmental injustice.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to maximize routing efficiency and reduce truck trips are envisioned as a “voluntary” measures to enhance operating efficiency and could be easily incorporated as a BMP in voluntary programs such as the NMED San Juan VISTAs program.

Furthermore, the state could adopt tax advantages strategies to allow companies to reduce their taxes by showing reduced emissions from adopting improved routing or operating efficiency. There are currently no mechanisms or rules to require mandatory efficiency standards and this seems implausible as a mandatory approach.

B. Indicate the most appropriate agency(ies) to implement: The states.

III. Feasibility of the option

A. Technical: The use of centralized facilities is technically feasible as is software to maximize routing efficiency.

B. Environmental: The environmental benefits of reduced vehicle mileage are well documented.

C. Economic: These options need to be explored by individual companies as to their economic viability.

IV. Background data and assumptions used

1. Water hauling is necessary in NM due to the lack of pipeline infrastructure to pipe the fluids directly to SWD facilities; Colorado has a greater use of pipelines.

2. Trucking companies will not react adversely to reduced economics from less vehicle miles.

V. Any uncertainty associated with the option Medium.

VI. Level of agreement within the work group for this mitigation option General agreement among drafting team members that this is viable and probable.

VII. Cross-over issues to other source groups None at this time.

Differing opinion: Some indication by the Cumulative Effects group of the potential emissions reduced would be helpful.

ENGINES: RIG ENGINES

Mitigation Option: Diesel Fuel Emulsions

I. Description of the mitigation option

Diesel Fuel Emulsions:

- This option, which is an EPA verified retrofit technology, reduces peak engine combustion temperatures and increases fuel atomization and combustion efficiency.
Differing opinion: The EPA study only looked at the “summer” blend of diesel emulsion. There is no data available to evaluate neither the compatibility with winter temperatures nor the emissions effects at winter temperatures.
- It is accomplished by using surfactant additives to encapsulate water droplets in diesel fuel to form a stable mixture while ensuring that the water does not contact metal engine parts.
- Air quality benefit:

Non-Road ¹	% Reductions ^{2,3}			
	PM	CO	NOx	HC
0-100 hp	23	(35)	19	(99)
100-175 hp	17	13	17	(80)
175-300 hp	17	13	19	(73)
>300 hp	17	13	20	(30)

1. Estimate using 2D fuel, <500 ppm sulfur.
 2. (##) indicates an increase
 3. Based on verification results supplied to EPA by Lubrizol for PuriNOx emulsion.
Differing Opinion: CARB’s verified NOx reductions were lower (14%) than EPA’s as shown in the above table. This suggests a need for a more extensive review prior to finalizing this option.
- Can be used in conjunction with a diesel oxidation catalyst to reduce HC and CO emissions and further reduce PM.
 - Emission control performance is better in lower load/lower speed applications.
 - Emulsions have about a 12-month shelf life.
 - Typically experience a 20% power loss when operating at maximum engine horsepower. The power loss is potentially a fatal flaw in this method. Most rig engines are sized for the maximum load expected and would have to be refitted with larger engines to handle the equivalent maximum loads.
 - Will expect a 15% increase in fuel consumption for equipment operating on fuel with emulsion additive. [This will increase SO2 emissions by 15%. The mass will depend on the sulfur content of the fuel. It will also increase fuel delivery truck emissions by 15% along with road dust emissions due to fuel hauling by 15%.
 - Not compatible with optical or conductivity-type fuel sensors, water absorbing water separators, water absorbing fuel filters, or centrifugal style water separators.
 - Engine must be run for at least 15 minutes every 30 days.
 - Incremental cost increase of \$0.10 to 0.20 per gallon.
- Differing opinion:** The increased fuel cost on top of the 15% increase in fuel consumption makes this a very expensive option. For a “typical” 16 day Wyoming Green River Basin well using 19,816 gallons of diesel, the 15% fuel penalty would represent about \$6,000 additional fuel cost and the average premium (\$0.15/gal) would represent about \$3,400 additional fuel cost for a NOx benefit of about 1 ton reduction – or a cost of about \$9,400 per ton of NOx. This seems very excessive and does not include the additional costs required for separate mixing and storage of the emulsified fuel. There may also be incremental labor costs for the technicians to operate the system. The incremental cost per gallon needs to be updated and verified – the cost quoted dates

to the original study date. Installation of oxidation catalyst to control hydrocarbon and CO emissions would add additional cost and complexity to an already cost prohibitive option.

- Requires mixing of fuel with emulsion and a storage unit for the emulsion and or mixed fuel. Some burden on technicians to properly operate and mix some simple equipment.

II. Description of how to implement

This voluntary option would be relatively simple using EPA verified retrofit technology. Some analysis is required to ensure that duty cycle (how long will engine and fuel be idle) and ambient temperatures are compatible with the emulsion product. Storage tanks and some training and capable technicians will be required to put into operation the relatively simple mixing equipment.

Differing opinion: The power penalties, incremental mixing and storage equipment, and increased technical knowledge necessary make this option do-able, but not necessarily simple.

III. Feasibility of the option

A. Technical: Technically this is one of the simplest options available.

B. Environmental: Fuel emulsion has potential for increased carbon monoxide and hydrocarbon emissions, but this downside could be overcome by use of a diesel oxidation catalyst. One additional issue with the emulsion option is that if the emulsion is no longer purchased or used the emission benefit goes away, in comparison to permanent exhaust treatments or improved engines or hardware.

C. Economic: There would be capital cost for emulsion and/or mixture storage and ongoing incremental cost per gallon.

Differing opinion: This option should be characterized as an expensive one. Using a “typical” 16 day Wyoming Green River Basin well using 19,816 gallons of diesel the 15% fuel penalty would represent about \$6,000 additional fuel cost and the average premium (\$0.15/gal) would represent about \$3,400 additional fuel cost for a NOx benefit of about 1 ton reduction – or a cost of about \$9,400 per ton of NOx. This seems very excessive and does not include the additional costs required for separate mixing and storage of the emulsified fuel. There may also be incremental labor costs for the technicians to operate the system.

IV. Background data and assumptions used

As an EPA verified retrofit, the data and assumptions associated with this option have been well evaluated and considered.

Differing opinion: The evaluation of applicability in cold weather needs to be done.

V. Any uncertainty associated with the option (Low, Medium, High)

Low uncertainty as this is a verified, simple retrofit.

Differing opinion: Given the high apparent cost, no evaluation in cold weather, different reduction percentages from separate evaluations, and complexity, this option should not be considered low uncertainty.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups (please describe the issue and which groups

None at this time.

Mitigation Option: Natural Gas Fired Rig Engines

I. Description of the mitigation option

Install natural gas fired engines on rigs in the Four Corners region.

Benefits

- Air Quality - Natural gas engines emit less and NO_x,
 - ~ 85% reduction of NO_x vs. Tier I engines.
Differing opinion: Given the variable load (and often low load) on drilling rig engines, the “best” lean burn natural gas engine performance expected would be in the range of 2 to 3 grams per hp-hr. This represents about a 65-75% reduction from Tier 1 diesel engines. Please note this would require lean burn engines.
 - ~ 91% reduction of NO_x vs. Tier 0 engines
Differing opinion: Given the variable load (and often low load) on drilling rig engines, the “best” lean burn natural gas engine performance expected would be in the range of 2 to 3 grams per hp-hr. This represents about a 65-75% reduction from Tier 1 diesel engines. Please note this would require lean burn engines.
 - Natural gas engines emit less particulate matter (PM) on a larger percent reduction basis than the NO_x percentages above.
- Cost Savings?
 - If the natural gas fuel source is in close proximity and little piping is required, its use may be less expensive than diesel, which is currently hauled to the rig.
Differing opinion: On a purely fuel basis this may be true without considering the retrofit costs.
 - Savings in fuel cost is dependent on product price.

Tradeoffs

- CO levels increase with natural gas usage, ~ 175%

Burdens

- Fuel Source
 - A natural gas fuel source sufficient to power the rig engines may not be readily available at every site.
 - Installation of piping to transport the natural gas may increase safety risks for workers and may potentially require right-of-way that can significantly delay projects (months to years).
 - Natural gas usage may require mineral owner approval, metering and appropriate allocation potentially resulting in permitting delays and increased administrative support
 - Fuel supply needs careful tuning and monitoring due to varying amounts of produced water that may be present. Also impacted by variations in fuel quality in the different areas and formations of a field. Could also require the installation of a dehydrator if gas is wet and the field uses a central dehydration system.
 - Engine size must increase to achieve an equivalent horsepower yield. For example a Cat 3512 diesel would have to be replaced with a Cat 3516 natural gas engine to get approximately the same horsepower.
- Rig Operations
 - Slower power response and less torque requires learning curve on rigs
 - Not well suited for Mechanical Rigs – Electric rigs are preferred. Information from natural gas fueled engine rigs in Wyoming indicates that a “load bank” is required due to the slower response of the engines to power demand.
- Cost
 - Initial Capital Investment – up to 1.2 MM\$ / Rig for retrofit

- If the natural gas fuel source is distant or not available for other reasons, the associated piping or use of LNG may be significantly more expensive than diesel.

Differing opinion: LNG is not a viable fuel – it is not readily available, requires refrigerated storage, and requires “re-gas” equipment. Conversion to natural gas fuels essentially limits the utility of a particular rig to just those instances where gas is available.

- Availability
 - Engine availability is limited

II. Description of how to implement

A. Mandatory or voluntary: Voluntary

B. Indicate the most appropriate agency(ies) to implement: None

III. Feasibility of the option

A. Technical: A natural gas fired rig engine is currently being utilized in Wyoming in the Jonah Field indicating that the technology works. However, the Jonah field is significantly different from the San Juan Basin enabling easier access to natural gas as a fuel source. The wells in the Jonah Field are more closely spaced (10 acre vs. 80 acre) and deeper allowing for the directional drilling of several wells from a single well pad and close proximity to currently producing wells.

B. Environmental: Installation of natural gas fired engines on new rigs will significantly reduce NOx emissions for those rigs, but may result in other environmental impacts, including an increase in CO emissions and potential land disturbance related to installation of natural gas pipelines to deliver the fuel.

C. Economic: In some cases where a natural gas fuel source is nearby, fuel costs may be lower than for diesel. In other cases, where access to natural gas can only be obtained by installing a large amount of pipe that potentially requires a right-of-way or by using LNG, the costs may be significantly higher. Conversion to natural gas fired engines essentially limits the use of a rig to only those instances where gas is available. The conversion/retrofit costs are high.

Differing opinion: See LNG comments above.

IV. Background data and assumptions used

Utilized Encana data obtained from Ensign 88 – Natural Gas Rig (2 3516 LE Natural Gas Engines on 1200 KW Generators)

V. Any uncertainty associated with the option (Low, Medium, High) High

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to other source groups

Mitigation Option: Selective Catalytic Reduction (SCR)

I. Description of the mitigation option

Selective Catalytic Reduction (SCR)

Description

Selective catalytic reduction (SCR) is the process where a reductant (typically ammonia or urea) is added to the flue gas stream and is absorbed onto the catalyst (typically vanadium or zeolite) enabling the chemical reduction of NO_x to molecular nitrogen and water. Diesel engines typically have unconsumed oxygen in the exhaust, which inhibits removal of oxygen from the NO_x molecules. To remove the unconsumed oxygen, the catalyst decomposes the reductant causing the release of hydrogen, which reacts with the oxygen. This creates local oxygen depletion near the catalyst allowing the hydrogen to also react with the NO_x molecules to form nitrogen and water.

Benefits

- NO_x emission reductions of 80-90% are achieved. NO_x emission reductions of up to 80-90% are achievable.
- Potential to reduce hydrocarbon, hazardous air pollutant, and condensable particulate matter (PM) emissions based on emissions tests.
- Technology is available currently.
- SCR systems designed primarily to reduce NO_x have been designed with PM filtering capabilities.

Tradeoffs

- Ammonia Slip

The SCR process requires precise control of the ammonia injection rate. An insufficient injection may result in unacceptably low NO_x conversions. An injection rate that is too high results in release of undesirable ammonia to the atmosphere. These ammonia emissions from SCR systems are known as *ammonia slip*. Ammonia slip will also occur when exhaust gas temperatures are too cold for the SCR Reaction to occur. Ammonia slip can potentially be controlled by an oxidation catalyst installed downstream of the SCR catalyst. Diesel oxidation catalysts are often used downstream of NO_x catalysts for ammonia reduction.

Burdens

- Minimum and maximum temperature ranges limit the effectiveness of the SCR system.
 - The SCR system requires a minimum exhaust temperature of 572°F (300°C) and maximum of 986°F (530°C) for NO_x reduction to occur (optimal range).
- The SCR systems had faults and system errors that can shut the urea injection system off.
 - ENSR testing had problems with the NO₂ measuring cells that had multiple high and low pressure and measurement alarms.
- The SCR system needs operator attention.
 - The SCR system needs to be tuned to the engine operating cycle. This requires running the engine through a simulation of the operating cycle of the machine it will be fitted to (engine mapping).
 - Typically SCR catalysts require frequent cleaning even with pure reductants, as the reductant can cake the inlet surface of the catalyst while the exhaust gas stream temperature is too low for the SCR reaction to take place.
- Potential for ammonia slip
- Cost (Retrofit)
 - Capital Expenditure Costs - ~\$130,000 / new SCR unit

- Operating Expenditure Costs - ~\$143,000 / year / unit 1
- Costs extrapolated out over a 10-year period would equate to **\$1.56 MM / engine equipped.**
- Need for reductant (NH3) adds to the engine operating cost (in the range of 4% of the equipment operating fuel cost).

Non-Selective Catalytic Reduction (NSCR)

NSCR is not applicable to diesel engines.

II. Description of how to implement

A. Mandatory or voluntary: The workgroup believes that more information is required on the contribution of rig emissions to the total NOx emissions and the potential ammonia emissions impact to visibility prior to determining whether this mitigation should be mandatory or voluntary.

B. Indicate the most appropriate agency(ies) to implement: The states.

III. Feasibility of the option

A. Technical: The technology is available and effective in reducing NOx emissions.

B. Environmental: Proven reduction of NOx emissions, however the potential increase of ammonia emissions and subsequent impact to visibility is not well understood.

C. Economic: Capital costs associated with a new engine with SCR or installation of retrofit SCR are feasible. Additional costs associated with operation and maintenance may not be feasible for some rig operators.

IV. Background data and assumptions used

Utilized information from ENSR Presentation - *Technology Demonstration – Selective Catalytic Reduction (SCR) and Bi-Fuels Implementation on Drill Rig Engines*

V. Any uncertainty associated with the option (Low, Medium, High)

Medium – It is clear that SCR is effective in reducing NOx emissions, however an understanding of the potential increase of ammonia emissions and the resulting impacts to visibility need to be understood.

VI. Level of agreement within the work group for this mitigation option

The workgroup agrees that this is a potential mitigation option, but requires more information regarding ammonia emissions and the overall contribution of NOx emissions from rigs.

EPA has SCR listed as a Potential Retrofit Technology for diesel engines.

VII. Cross-over issues to the other source groups (please describe the issue and which groups

Cumulative Effects Workgroup – The Rig Engines Drafting Workgroup requires information on the estimated contribution of NOx emissions from rig engines and on the impact of ammonia emissions on visibility (what are local levels currently, how will increasing ammonia emissions impact visibility?).

Mitigation Option: Selective Non-Catalytic Reduction (SNCR)

I. Description of the mitigation option

Selective Non-Catalytic Reduction (SNCR) is a post-combustion treatment in which ammonia is injected into the flue gas stream. The ammonia reacts with the NO_x compounds, forming nitrogen and water. In order for this technique to be effective, the ammonia must be injected at a proper temperature range within the stack and must be in the proper ratio to the amount of NO_x present. The reduction reaction at temperatures ranging from 925 – 1125°C does not require catalysis and can achieve 40% NO_x control. More modest NO_x reductions are reported in the 725 - 925°C range.

Differing Opinion: These are very high temperatures and much greater than the temperatures in diesel engine exhaust. For example, the data sheet for a Cat 3512 diesel rig engine shows a “highest” exhaust temperature of ~792 degrees F. Based on the degradation in performance reported in the 725 – 925 degrees C it probably would have very little effect at the exhaust temperatures from rig engines. This technology is really tested for very high temperature boilers only – not engines.

Benefits

- NO_x emission reductions of ~40% (range 20-55%) are achieved in optimal temperature range.
- Avoids the expense of a catalyst.
- Technology is available currently.

Tradeoffs

- Ammonia Slip – 10 ppm ammonia slip is considered reasonable for SNCR. 10 ppm represents about 16 tons/yr of ammonia from a single fully loaded Cat 3512 engine. Given that most rigs have two or more engines it is not much of a stretch to have very significant ammonia emissions with the number of rigs running in the basin. This amount of ammonia may enhance secondary particulate formation with consequent effects on PM 2.5 (health based) and visibility (perception based).

Burdens

SNCR tends to have high operating costs - cost is estimated at \$600 - \$1300/ton

Mobile source engines (rig engines) are usually not a good candidate for SNCR because typical operating temperatures are below the levels needed for effective operation.

II. Description of how to implement

A. Mandatory or voluntary: The workgroup believes that more information is required on the contribution of rig emissions to the total NO_x emissions and the potential ammonia emissions impact to visibility prior to determining whether this mitigation should be mandatory or voluntary.

B. Indicate the most appropriate agency(ies) to implement: Colorado Department of Public Health and Environment (CDPHE), New Mexico Environment Department (NMED).

III. Feasibility of the option

A. Technical: The technology is available and effective in reducing NO_x emissions.

Differing Opinion: There is no available data indicating applicability to engines or much lower temp operation. This option should be considered as non-feasible.

B. Environmental: Proven reduction of NO_x emissions, however the potential increase of ammonia emissions and subsequent impact to visibility is not well understood.

C. Economic: Costs associated with operation and maintenance may not be feasible for some rig operators.

IV. Background data and assumptions used

State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines – State of New Jersey, Department of Environmental Protection, Division of Air Quality

V. Any uncertainty associated with the option

Medium – SNCR is effective in reducing NO_x emissions, however an understanding of the potential increase of ammonia emissions and the resulting impacts to visibility need to be understood.

VI. Level of agreement within the work group for this mitigation option

The workgroup agrees that this is a potential mitigation option, but requires more information regarding ammonia emissions and the overall contribution of NO_x emissions from rigs.

VII. Cross-over issues to the other source groups

Cumulative Effects Workgroup – The Rig Engines Drafting Workgroup requires information on the estimated contribution of NO_x emissions from rig engines and on the impact of ammonia emissions on visibility (what are local levels currently, how will increasing ammonia emissions impact visibility?).

Mitigation Option: Implementation of EPA's Non Road Diesel Engine Rule – Tier 2 through Tier 4 Standards

I. Description of the mitigation option

In short this option would require the use of engines that at minimum meet EPA Tier 2 non-road on a fleet average basis and that all newly installed engines would meet the most current EPA standard (Tier 2 through 4).

In 1998, EPA adopted more stringent emission standards ("Tier 2" and "Tier 3") for NO_x, hydrocarbons (HC), and PM from new nonroad diesel engines. This program includes the first set of standards for nonroad diesel engines less than 50 hp (phasing in between 1999 and 2000), phases in more stringent "Tier 2" emission standards from 2001 to 2006 for all engine sizes, and adds more stringent "Tier 3" standards for engines between 50 hp and 750 hp from 2006 to 2008.

In June 2004, EPA adopted additional nonroad diesel engines emission standards. These standards are known as "Tier 4." This comprehensive national program regulates nonroad diesel engines and diesel fuel as a system. New engine standards will begin to take effect in the 2008 model year, phasing in over a number of years.

The pertinent regulations are as follows:

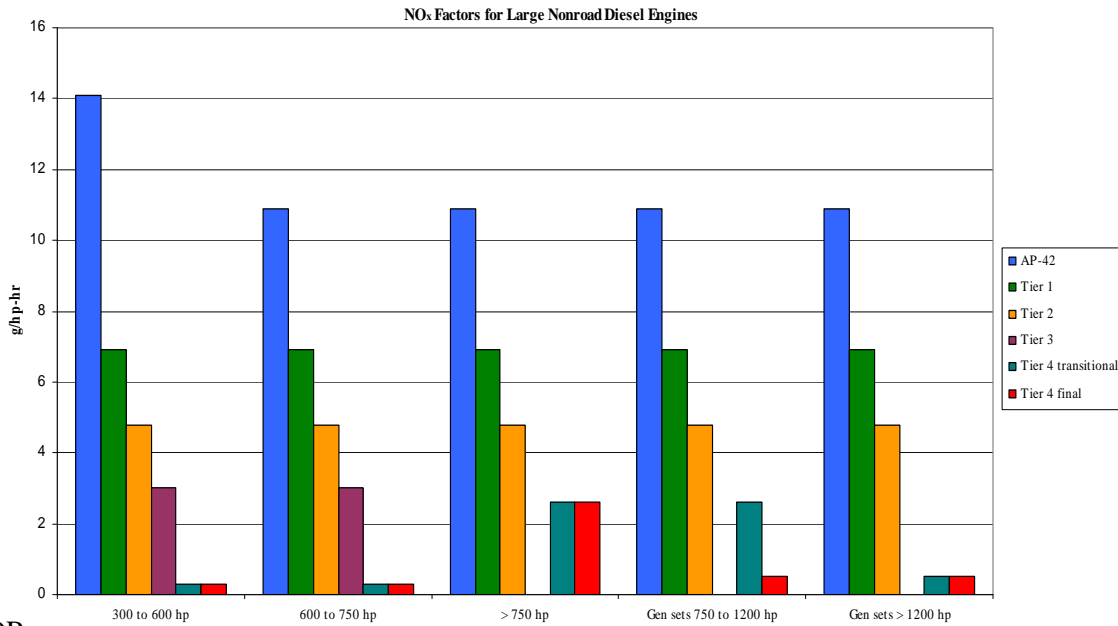
Clean Air Nonroad Diesel - Tier 4 Final Rule: Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel, 69 FR 38957, June 29, 2004

Tier 2 and Tier 3 Emission Standards - Final Rule: Control of Emissions of Air Pollution from Nonroad Diesel Engines, 63 FR 56967, October 23, 1998

Drill rig engines would be considered "non-road engines" because of the definition of non-road engine in 40 CFR 1068.30 (1)(iii) and (2)(iii) – assuming the rig moves more often than every 12 months.

These non-road diesel standards do not apply to existing non-road equipment. Only equipment built after the start date for an engine category (1999- 2006, depending on the category) is affected by the rule.

The Tier 2, 3, and 4 Emission Standards for large (> 300 hp) are as follows: [AP42 (Tier 0) and Tier 1 shown for comparison purposes]



OR

	300 to 600 hp	600 to 750 hp	> 750 hp (Excluding Gen Sets)	Gen sets 750 to 1200 hp	Gen sets > 1200 hp
AP-42	14.1*	10.9**	10.9**	10.9**	10.9**
Tier 1	6.9	6.9	6.9	6.9	6.9
Tier 2	4.8	4.8	4.8	4.8	4.8
Tier 3	3	3			
Tier 4 transitional	0.3	0.3	2.6	2.6	0.5
Tier 4 final	0.3	0.3	2.6	0.5	0.5

*AP-42 Table 13-1

**AP-42 Table 14-1

shading -- NMHC + NOx

The Tier 2, 3, and 4 Emission Standards for large (> 300 hp) are as follows: [AP42 (Tier 0) and Tier 1 shown for comparison purposes]

Effective Dates of Tier Standards, Nonroad Diesel Engines, by Horsepower

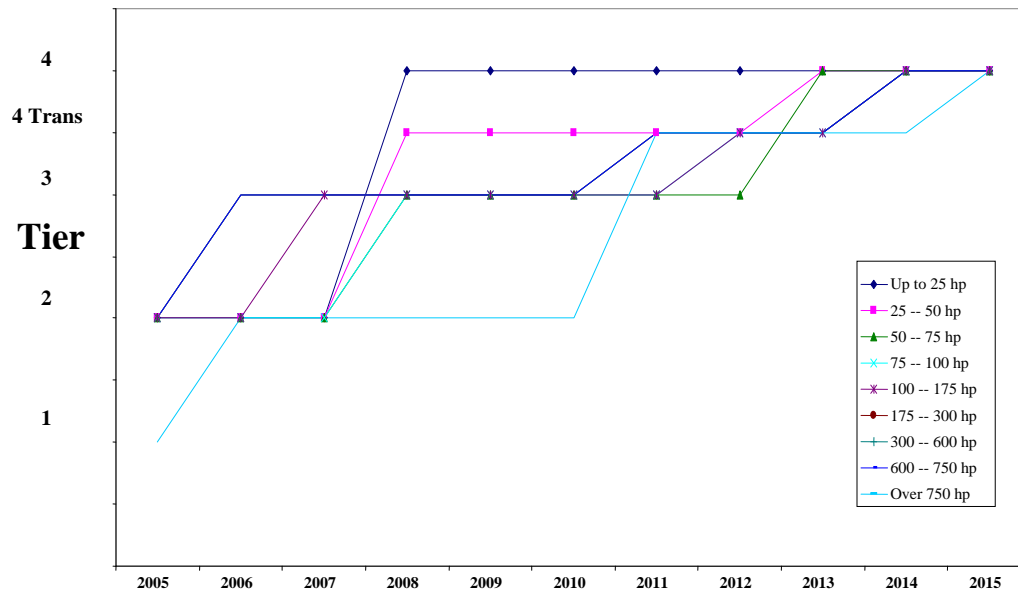


Table 1. Nonroad CI Engine Emission Standards^a

Engine Power (hp)	Model Years	Regulation	Emission Standards (g/hp-hr)					NONROAD Tech Types
			HC ^b	NMHC+NO _x	CO	NO _x	PM	
<11	2000-2004	Tier 1		7.8	6.0		0.75	T1
	2005-2007	Tier 2		5.6	6.0		0.60	T2
	2008+	Tier 4					0.30	T4A, T4B *
≥11 to <25	2000-2004	Tier 1		7.1	4.9		0.60	T1
	2005-2007	Tier 2		5.6	4.9		0.60	T2
	2008+	Tier 4					0.30	T4A, T4B *
≥25 to <50	1999-2003	Tier 1		7.1	4.1		0.60	T1
	2004-2007	Tier 2		5.6	4.1		0.45	T2
	2008-2012	Tier 4 transitional					0.22	T4A
	2013+	Tier 4 final		3.5			0.02	T4
50 to <75	1998-2003	Tier 1				6.9		T1
	2004-2007	Tier 2		5.6	3.7		0.30	T2
	2008-2012	Tier 3 ^c		3.5	3.7			T3
	2008-2012	Tier 4 transitional ^c					0.22	T4A
	2013+	Tier 4 final		3.5			0.02	T4
≥75 to <100	1998-2003	Tier 1				6.9		T1
	2004-2007	Tier 2		5.6	3.7		0.30	T2
	2008-2011	Tier 3		3.5	3.7			T3B
	2012-2013	Tier 4 transitional	0.14 (50%) ^d			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
≥100 to <175	1997-2002	Tier 1				6.9		T1
	2003-2006	Tier 2		4.9	3.7		0.22	T2
	2007-2011	Tier 3		3.0	3.7			T3
	2012-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
≥175 to <300	1996-2002	Tier 1	1.0		8.5	6.9	0.4	T1
	2003-2005	Tier 2		4.9	2.6		0.15	T2
	2006-2010	Tier 3		3.0	2.6			T3
	2011-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N

Engine Power (hp)	Model Years	Regulation	Emission Standards (g/hp-hr)					NONROAD Tech Types
			HC ^b	NMHC+NO _x	CO	NO _x	PM	
≥ 300 to <600	1996-2000	Tier 1	1.0		8.5	6.9	0.4	T1
	2001-2005	Tier 2		4.8	2.6		0.15	T2
	2006-2010	Tier 3		3.0	2.6			T3
	2011-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
≥ 600 to ≤ 750	1996-2001	Tier 1	1.0		8.5	6.9	0.4	T1
	2002-2005	Tier 2		4.8	2.6		0.15	T2
	2006-2010	Tier 3		3.0	2.6			T3
	2011-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
>750 except generator sets	2000-2005	Tier 1	1.0		8.5	6.9	0.4	T1
	2006-2010	Tier 2		4.8	2.6		0.15	T2
	2011-2014	Tier 4 transitional	0.30			2.6	0.075	T4
	2015+	Tier 4 final	0.14			2.6	0.03	T4N
Generator sets >750 to ≤ 1200	2000-2005	Tier 1	1.0		8.5	6.9	0.4	T1
	2006-2010	Tier 2		4.8	2.6		0.15	T2
	2011-2014	Tier 4 transitional	0.30			2.6	0.075	T4
	2015+	Tier 4 final	0.14			0.5	0.02	T4N
Generator sets >1200	2000-2005	Tier 1	1.0		8.5	6.9	0.4	T1
	2006-2010	Tier 2		4.8	2.6		0.15	T2
	2011-2014	Tier 4 transitional	0.30			0.5	0.075	T4
	2015+	Tier 4 final	0.14			0.5	0.02	T4N

^a These standards do not apply to recreational marine diesel engines over 50 hp. Standards for this category are provided in Table 7.

^b Tier 4 standards are in the form of NMHC.

^c For 50 to <75 hp engines, a Tier 3 NO_x standard of 3.5 g/hp-hr was promulgated, beginning in 2008. The Tier 4 transitional standard also begins in 2008; it leaves the Tier 3 NO_x standard unchanged and adds a 0.22 g/hp-hr PM standard.

^d Percentages are model year sales fractions required to comply with the indicated NO_x and NMHC standards, for model years where less than 100 percent is required.

^e The T4A tech type is used in 2008-2012. The T4B tech type is used in 2013+.

II. Description of how to implement

A. Mandatory or voluntary

Compliance with these regulations is required for new and rebuilt engines after the specified deadlines. The Four Corners Task Force is studying the potential for quicker implementation of the standards based on a voluntary agreement to either retrofit existing engines to meet the Tier 2 through Tier 4 standards or use of new Tier 2 through Tier 4 compliant engines.

B. Indicate the most appropriate agency(ies) to implement

EPA implements the non-road engine regulations nationally by certifying engine manufacture test results, but state regulatory agencies would be involved in any agreements for accelerated implementation of the standards in the Four Corners area.

III. Feasibility of the option

A. Technical

Some engine industry authorities indicate anecdotally that the supply of the new, cleaner engines may fall short of the demand for them particularly in the oil and gas industry.

In 1998, EPA adopted more stringent emissions standards for nonroad diesel engines. In that rulemaking, EPA indicated that in 2001 it would review the upcoming Tier 3 portion of those standards (and the Tier 2 emission standards for engines under 50 horsepower) to assess whether or not the new standards were technologically feasible. EPA drafted a technical paper with a preliminary assessment of the technological feasibility of the Tier 2 and Tier 3 emission standards - <http://www.epa.gov/nonroad-diesel/r01052.pdf>

In this assessment EPA determined that the standards were feasible with technologies such as the following:

Charge Air Cooling - Air-to-air or air-to-water cooling at intake manifold reduces peak temperature of combustion. (Controls NO_x)

Fuel Injection Rate Shaping & Multiple Injections - Controls fuel injection rate, limiting rate of increase in temperature & pressure. (Controls NO_x)

Ignition Timing Retard - Delays start of combustion, matching heat release with power stroke. (Controls NO_x)

Exhaust Gas Recirculation - (1) Reduces peak cylinder temperature, (2) dilutes O₂ with inert gases, (3) dissociates CO₂ & H₂O endothermic. (Controls NO_x)

B. Environmental

The Tier 2 and 3 standards will reduce emissions from a typical nonroad diesel engine by up to two-thirds from the levels of previous standards. By meeting these standards, manufacturers of new nonroad engines and equipment will achieve large reductions in the emissions (especially NO_x and PM) that cause air pollution problems in many parts of the country. EPA estimates that by 2010, NO_x emissions nationally will be reduced by about a million tons per year because of the Tier 2 and 3 standards.

When the full inventory of older nonroad engines are replaced by Tier 4 engines, annual emission reductions nationally are estimated at 738,000 tons of NO_x and 129,000 tons of PM. By 2030, 12,000 premature deaths would be prevented annually due to the implementation of the proposed standards. EPA estimates that NO_x emissions from these engines will be reduced by 62 percent in 2030.

C. Economic

EPA estimates the costs of meeting the Tier 2 and 3 emission standards are expected to add well under 1 percent to the purchase price of typical new non-road diesel equipment, although for some equipment the standards may cause price increases on the order of two or three percent. The program is expected to cost about \$600 per ton of NO_x reduced, which compares very favorably with other emission control strategies.

The estimated costs for added emission controls for the vast majority of equipment was estimated at 1-3% as a fraction of total equipment price. For example, for a 175 hp bulldozer that costs approximately \$230,000 it would cost up to \$6,900 to add the advanced emission controls and to design the bulldozer to accommodate the modified engine.

EPA estimated that the average cost increase for 15 ppm sulfur diesel fuel will be seven cents per gallon. This figure would be reduced to four cents by anticipated savings in maintenance costs due to low sulfur diesel.

IV. Background data and assumptions used (indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)

The Cumulative Effects group could assess how much air quality improvement would be realized from implementation of the Tier 2 through Tier 4 standards by a specified percent of rig engines in the Four Corners area, by timeframes specified in regulation or some accelerated schedule. The group could also address the number of days of visibility improvement, and the reduced flux of Nitrogen deposition.

V. Any uncertainty associated with the option (Low, Medium, High)

Low, these diesel engine standards must be met nationally by the specified dates. The primary uncertainty raised so far is related to supply of new engines sufficient to meet demand. EPA has studied the technological feasibility of the Tier 2 and Tier 3 emission standards and has determined that they are feasibility [see <http://www.epa.gov/nonroad-diesel/r01052.pdf>]

VI. Level of agreement within the work group for this mitigation option N.A. for complying with national regulations.

VII. Cross-over issues to the other source groups (please describe the issue and which groups

All new “non-road” diesel engines used in the Four Corners area will have to comply with these regulations.

Mitigation Option: Interim Emissions Recommendations for Drill Rigs

I. Description of the mitigation option

The following mitigation option paper is one of three that were written based on interim recommendations that were developed prior to the convening of the Four Corners Air Quality Task Force. Since the Task Force's work would take 18-24 months to finalize, and during this time oil and gas development could occur at a rapid pace, an Interim Emissions Workgroup made up of state and federal air quality representatives was formed to develop recommendations for emissions control options associated with oil and gas production and transportation. The Task Force includes these recommendations as part of its comprehensive list of mitigation options.

NOx emissions from drill rigs are significant on a year round basis and should be reduced by a requirement that rig engines meet Tier 2 standards.

- NOx emissions from rigs contribute to visibility degradation
- This recommendation is consistent with EPA Region 8's oil and gas initiative and recent Wyoming DEQ recommendations
- The requirement may be impractical for BLM to enforce

States should analyze potential initiatives to achieve emissions reductions from these sources to reduce deposition, the cumulative impacts to visibility, and to ensure compliance with the NAAQS and PSD increments.

II. Description of how to implement

NOx emission limits determined by Tier 2 would be mandatory for new rigs and voluntary for existing equipment. The agencies to enforce this would be BLM and the New Mexico and Colorado departments of environmental quality.

III. Feasibility of the Option

The feasibility of Tier 2 requirements for new rig engines has been demonstrated in commercial applications. The environmental benefits include PM and NOx reductions. The economic feasibility depends on using the technology with new rigs. The cost for replacement of an existing engine would be high since there might be no market for the used engine.

IV. Background data and assumptions used

The technology for rig engine upgrade to Tier 2 standards is based on the requirement to use Tier 2 certified diesel engines on new rigs. Under certain circumstances, upgrades might be required on older rigs as well.

V. Any uncertainty associated with the option

Tier 2 engines are currently being manufactured, but some uncertainty exists about the effectiveness of add-on controls to meet Tier 2 levels for existing rig engines.

VI. Level of agreement within the work group for this mitigation option

TBD.

VII. Cross-over issues to the other source groups

None.

Mitigation Options: Various Diesel Controls

Duel Fuel (or Bi-fuel) Diesel and Natural Gas; Biodiesel; PM Traps; Free Gas Recirculation; Fuel Additives; Liquid Combustion Catalyst; Lean NOx Catalyst; Low NOx ECM - Engine Electronic Control Module (ECM) Reprogram; Exhaust Gas Recirculation (EGR)

I. Description of the mitigation options

Duel fuel (or Bi-fuel) diesel and natural gas

This system allows engines to run on a blend of diesel and natural gas fuels. The systems consist of an air to fuel (AFR) controller and a fuel mixing chamber. The AFR constantly adjusts the fuel to air mixture being delivered to the piston chambers and optimizes the stoichiometric relationship in order to balance the NOx and CO emissions. The mixing chamber establishes the diesel to natural gas mixing ratio. This system is being tested on drill rig diesel engines in the Pinedale, WY area. There are preliminary results based on tests of three engines (Cat 398 & 399) Pros: Operators reported that rig engine fuel costs were reduced by ~ \$700 per day, requires minimal engine modification, and has a small footprint. Cons: Does not conclusively reduce NOx, increases CO and HC emissions, and the system needs frequent oversight to ensure operation.

Biodiesel

Biodiesel fuel stock comes from vegetable oil, animal fats, and waste cooking oils. Biodiesel can be blended at different percentages up to 100% (typically 5 – 20%). Biodiesel at a 20% blend can reduce PM mass emissions by up to 10%, reduce HC and CO up to 20%, and may slightly increase NOx emissions. Use of biodiesel requires little or no modification to fuel system or engine. Cold temperatures require special fuel handling such as additives or heating fuel system. EPA listed “verified retrofit technology.”

PM Traps

Diesel particulate filters (DPFs) collect or trap PM in the exhaust. DPFs consist of a filter encased in a steel canister positioned in the exhaust system. DPFs need a mechanism to remove the PM (regeneration or cleaning) and to monitor for engine backpressure. DPFs types have different reduction capabilities and applications. DPFs can be used in conjunction with catalysts (catalyst based (CB) DPFs) to obtain the most effective PM control for a retrofit technology. CB-DPFs can have over 90% PM mass reduction and over 99% carbon based PM reduction. CB-DPFs can also control CO and HC resulting in near elimination of diesel smoke and odor.

Flow through filters (FTFs), or partial flow filters, use a variety of media and regeneration strategies. The filter media can be either wire mesh or pertubated path metal foil. FTFs are a relatively new technology. FTF can be catalyzed or used in combination with Diesel Oxidation Catalysts (DOCs) or Fuels Borne Catalysts (FBCs). PM reduction efficiencies range from 25 to over 60% depending on the type of technology and duty/test cycle. FTFs have the potential for greater application than conventional DPFs. Some designs can be used on engines fueled with < 500 ppm sulfur fuel but efficiency decreases. Has the potential for use on older engines, but high PM levels can overwhelm even a FTF system. Adequate exhaust temperatures are needed to support filter regeneration.

Diesel exhaust PM traps are EPA listed “verified retrofit technology.”

Free Gas Recirculation

Crankcase emissions from diesel engines can be substantial. To control these emissions, some diesel engine manufacturers make closed crankcase ventilation (CCV) systems, which return the crankcase blow-by gases to engine for combustion. CCV systems prevent crankcase emissions from entering the atmosphere. Aftermarket open crankcase ventilations (OCV) are available which provide incremental improvements over engines with no crankcase controls, but they still allow crankcase emissions to be

released into the atmosphere. A retrofit CCV crankcase emission control (CCV) system has been introduced and verified for on-road applications by both the U.S EPA and CARB. Crankcase emissions range from 10% to 25% of the total engine emissions, depending on the engine and the operating duty cycle. Crankcase emissions typically contribute to a higher percentage (up to 50%) of total engine emissions when the engine is idling. The combined CCV/DOC system controls PM emissions by up to 33%, CO emissions by up to 23% and HC emissions by up to 66%.

Fuel Additives

Fuel additives are chemical added to the fuel in small amounts to improve one or more properties of the base fuel and/or to improve the performance of retrofit emission control technologies. Several cetane enhancers have been verified by EPA that reduce NO_x 0 to 5%. Other additives are undergoing verification. There thousands of fuel additives on the market that have no emission or fuel efficiency benefit so it is important to verify the manufacturer's claims regarding benefits. EPA listed "verified retrofit technology."

Liquid Combustion Catalyst

Fuels borne catalyst systems (FBCs) are marketed as a stand-alone product or as part of a system combined with DPFs, FTFs, or DOCs. FBCs have included cerium, cerium/platinum copper, iron/strontium, manganese and sodium. A DPF must be used to collect the catalyst additive so it cannot be emitted to the air. A FBC/DOC system has been verified by EPA to reduce PM 25 – 50%, NO_x 0 – 5%, and HC 40 – 50%. A FBC/FTF system has been verified by EPA to reduce PM 55 – 76%, CO 50 – 66%, and HC 75 – 89%. The estimated cost of the verified FBC is approximately \$.05 per gallon. Pre-mixed fuel is recommended for retrofit applications. FBCs do not require ultra low sulfur diesel and work with a wide range of engine sizes and ages. EPA listed "verified retrofit technology."

Lean NO_x Catalyst

Lean NO_x catalyst (LNC) is a flow through catalyst technology similar to diesel oxidation catalyst that is formulated for NO_x control. It typically uses diesel fuel injection ahead of the catalyst to serve as NO_x reduction. Lean NO_x catalyst can achieve a 10% to over 25% NO_x reduction. It can be combined with diesel oxidation catalyst (DOC) or diesel particulate filter (DPF). Over 3500 vehicles and equipment have been retrofitted with Lean NO_x catalyst and CB-DPF filter systems in United States. The sulfur level of the fuel has to be less than 15 ppm. Verified LNC systems use injected diesel fuel as the NO_x reducing agent and as a result a fuel economy penalty of up to 3% has been reported. EPA listed "potential retrofit technology."

Low NO_x ECM - Engine electronic control module (ECM) reprogram

Some engine manufacturers used ECM on 1993 through 1996 heavy-duty diesel engines that caused the engine to switch to a more fuel-efficient but higher NO_x mode during off cycle engine highway cruising. As part of the manufacturers' requirements to rebuild or reprogram older engines (1993-1998) to cleaner levels, companies developed a heavy-duty diesel engine software upgrade (known as an ECM "reprogram", "reflash" or "low NO_x" software) that modifies the fuel control strategy in the engine's ECM to reduce the excess NO_x emissions. Low NO_x ECM is available as a retrofit strategy to reduce NO_x emissions from certain diesel engines. Emissions control performance is engine specific. A system verified for a Cummins engine by CARB provided 85% particulate and 25% oxidation reductions. Over 60,000 heavy-duty diesel engines have received ECM reprograms. CARB plans to require ECM reprogramming on approximately 300,000 to 400,000 engines. ECM application is limited to heavy-duty diesel engines with electronic controls. Most off-road engines are not equipped with electronic controls. ECM is available throughout the U.S. through engine dealers and distributors. The software can be installed on-site and the reprogram takes approximately 15 to 30 minutes.

Exhaust Gas Recirculation (EGR)

The EGR system used in retrofit applications employs low-pressure. Original Equipment EGR systems typically employ high-pressure. EGR as a retrofit strategy is a relatively new development but has been proven durable and effective over the last few years. In the U.S. retrofit low-pressure EGR systems is combined with a CB-DPF to allow the proper functioning of the EGR component. EGR can reduce the NO_x formed by the CB-DPF. EGR/DPF systems have been verified by CARB. Over 3000 and exhaust gas recirculation diesel particulate filter systems have been retrofitted onto on road vehicles worldwide. EGR/DPF systems can be applied to off-road engines. However, experience is limited and the off-road market not the primary target application in the U.S. Current experience with EGR/DPF systems has been a range of 190 horsepower to 445 horsepower. The fuel economy penalty from EGR component ranges from 1% to 5% based on technology designed to particular engine and the test/duty cycle. EPA listed “potential retrofit technology.”

II. Description of how to implement

These controls would be voluntary retrofits for existing engines. Some of these controls may be used by engine manufacturers to meet EPA’s diesel standards for new engines.

III. Feasibility of the option

- A. Technical
- B. Environmental
- C. Economic

See the individual control summary descriptions above. For more detailed information consult Volume 2 of the WRAP Off-road Diesel Retrofit Guidance Document, to be found at:

http://www.wrapair.org/forums/msf/projects/offroad_diesel_retrofit/Offroad_Diesel_Retrofit_V2.pdf

IV. Background data and assumptions used

As EPA verified retrofits or potential retrofits (with the exception of the bi-fuel option), the data and assumptions associated with this option have been evaluated and considered. See EPA’s Voluntary Diesel Retrofit Program web pages (<http://www.epa.gov/otaq/retrofit/retroverifiedlist.htm> and <http://www.epa.gov/otaq/retrofit/retropotentialtech.htm>) and Volume 2 of the WRAP Off-road Diesel Retrofit Guidance Document, located at:

http://www.wrapair.org/forums/msf/projects/offroad_diesel_retrofit/Offroad_Diesel_Retrofit_V2.pdf for more information on these verified and potential retrofit controls.

V. Any uncertainty associated with the option

Low to high uncertainty depending on the application, engine, operating conditions. These are EPA verified or potential retrofits for diesel engines (with the exception of the bi-fuel option), but some controls are limited to specific applications.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

All existing or newly introduced diesel engines (on-road, non-road, and stationary) used in the 4 Corners area could utilize these control options with the limitations noted above.

ENGINES: TURBINES

Mitigation Option: Upgrade Existing Turbines to Improved Combustion Controls (Emulating Dry LoNOx Technology)

I. Description of the mitigation option

This option involves upgrading older units with improved electronic combustion control technology that approaches or meets Dry LoNOx for existing turbines and requires Dry LoNOx technology on all new turbines. The benefits of this mitigation option are lower NOx emissions, but it is an expensive option that may take several years to implement and may be difficult to achieve with some engine models. The tradeoffs is that a few people may spend a lot of money and not significantly impact overall nitrogen oxide emissions to meet the region's emission control objectives.

II. Description of how to implement

A. Mandatory or voluntary: Implementation should be assumed as voluntary until the existing turbine population is better understood.

Differing Opinion: The best technology should be mandatory.

B. Indicate the most appropriate agency(ies) to implement Federal, state, and tribal agencies responsible for air emissions compliance.

III. Feasibility of the option

A. Technical Individual turbine assessment will be needed to confirm appropriate size or design limitations (not all turbines can be retrofitted).

B. Environmental The benefits of a dry LoNOx emissions control technology on air emissions has been proven repeatedly for many large turbines.

C. Economic The economic impact cannot be understood without an inventory of installed turbines.

IV. Background data and assumptions used

No assumptions have been made at this time on the impact of emissions reductions due to the uncertainty of the existing turbine population.

V. Any uncertainty associated with the option High.

VI. Level of agreement within the work group for this mitigation option High.

VII. Cross-over issues to the other source groups

The impact of implementing this option may be further evaluated by the Cumulative Effects or Monitoring groups.

EXPLORATION & PRODUCTION: TANKS

Mitigation Option: Best Management Practices (BMPs) for Operating Tank Batteries

I. Description of the mitigation option

This option involves implementing and/or adoption of various Best Management Practices (BMPs) for operating tanks that contain crude oil and condensate. The specific BMPs include the use of Enardo valves, closing thief and other tank hatches, maintaining valves in leak-free condition, closing valves, etc. so as to minimize VOC losses to the atmosphere.

Economic burdens are minimal since these practices are largely followed and considered a normal cost of doing business as part of responsible operations.

There should not be any environmental justice issues associated with following these practices in socio-economically disadvantaged communities.

Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement BMPs for operating tank batteries are envisioned as “voluntary” measures to enhance operating efficiency and could be easily incorporated as a BMP in voluntary programs such as the NMED San Juan VISTAS program and EPA’s Natural Gas STAR Program. There are currently no mechanisms or rules to require BMPs as standards, and this seems implausible as a mandatory approach. Many companies have BMPs in place already.

B. Indicate the most appropriate agency(ies) to implement: The states.

III. Feasibility of the option

A. Technical: The use of BMPs for operating tank batteries is technically feasible as is software to maximize routing efficiency.

B. Environmental: The environmental benefits of reduced VOC pollution are well documented.

Differing opinion: Quantification of emission reductions from implementation of this mitigation option is not possible.

C. Economic: These BMPs need to be explored by individual companies as to their economic viability.

IV. Background data and assumptions used

1. Tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the lack of pipeline infrastructure to pipe the fluids directly to refineries.
2. Oil and gas producing companies will need to educate their workforce on the validity and importance of these BMPs.
3. Employees will not react adversely to following these practices as a normal course of being a lease operator.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option

General agreement within working group members that this is viable and probable.

Mitigation Option: Installing Vapor Recovery Units (VRU)

I. Description of the mitigation option

This option involves using Vapor Recover Units (VRUs) on crude oil and condensate tanks so as to capture the flash emissions that result when crude oil or condensate is dumped into the tank from the production separator. The air quality benefits would be to minimize VOC losses to the atmosphere and if sufficient flash gas were present, there would be economic benefits as well.

Economic burdens are substantial since these units are costly to install and maintain.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.

Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement VRUs for operating tank batteries are envisioned as “voluntary” measures since the feasibility of VRUs in the Four Corners area is negative. In certain areas of the country where ozone non-attainment areas exist, VRUs are commonly mandated by the respective Air Quality Control agency as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). Since the Four Corners area is not in ozone non-attainment and the costs economics will not generally justify installation of VRUs for economic benefit, a voluntary approach is recommended.

B. Indicate the most appropriate agency(ies) to implement: The states.

III. Feasibility of the option

A. Technical: The use of VRUs for operating tank batteries is technically feasible.

Differing opinion: However, installation of a VRU to most existing tank installations is not likely feasible without a complete redesign and new installation. Most tanks are pressure rated at 3-5 psig and would need to be replaced with tanks designed with higher pressure rating to handle pressure surges during separator dumps. Additional pressure relief valving, pressure regulators and other safety devices would need to be included with these systems. Redesign and system replacement would need to be evaluated to determine the economic feasibility of this type of system. As these tanks are under pressure there would be additional operational and safety issues related to proper product transfer and handling. Most transporters are not equipped to handle pressurized product transfers at present. Due to the small amount of condensate produced in 4-Corners wells, the periodic “dumping” from the separators to the tanks, and the consequent uneven flash of gas from the condensate the use of VRU’s is technically very challenging and may not be technically feasible. VRU’s start from atmospheric pressure and boost gas to low pressure that may not be sufficient to flow into the collection system lines. In this case, they are either not feasible or would require additional compression. The lack of electricity in the fields effectively precludes any operationally feasible VRU use.

B. Environmental: The environmental benefits of reduced VOC pollution are well documented. Benefits are relative to production throughputs. VOC emissions from flashing emissions are a function of well pressure and condensate production. The amount of emission reduction will be proportional to the amount of uncontrolled VOC emissions. Even if VRU’s can be made to work in the 4-corners area, the amount of VOC emission reduction per tank will be low due to the low condensate production rate.

C. Economic: The use of VRUs for recovering the flash emissions from produced crude oil/condensate are economically feasible where the Gas Oil Ratio (GOR) from produced crude oil/condensate is high and the daily production volume is at least 50 barrels/day or greater. Most wells in the Four Corners area typically produce less than 1 bbl/day of crude oil or condensate so VRUs are not economically feasible.

Flares or combustors could be considered an alternative control technology if sufficient VOC emissions exist. At 1 bbl/day and low pressure drop the flash gas volume and VOC content will not justify control systems.

IV. Background data and assumptions used

1. Tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the lack of pipeline infrastructure to pipe the fluids directly to refineries.
2. The minimal production levels for most wells make the use of VRU economically infeasible.

V. Any uncertainty associated with the option Low.

Differing opinion: MEDIUM based on availability of power, high maintenance requirements and reliability/performance.

Differing opinion: This would rank a high level of uncertainty in actually achieving meaningful and cost effective emission reductions using this technology.

VI. Level of agreement within the work group for this mitigation option

General agreement within working group members that the use of VRUs in the Four Corners areas is economically infeasible and an unlikely source for voluntary adoption.

Mitigation Option: Installing Gas Blankets Capability

I. Description of the mitigation option

This option involves modifying existing and installing new designed crude oil and condensate tanks that would be capable of placing an inert gas blanket over these tanks to minimize vapor loss. The inert gas would fill the space above the condensate/crude oil to minimize volatilization and vapor loss. The air quality benefits would be to minimize VOC losses to the atmosphere and if sufficient flash gas is present, there would be economic benefits as well.

Economic burdens are substantial since these units are costly to install and maintain.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.

Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement gas blankets for operating tank batteries are envisioned as “voluntary” measures since the feasibility of gas blanket technology in the Four Corners area is negative. In certain areas of the country where ozone non-attainment areas exist, gas blanket technology is one of several measures commonly mandated by the respective Air Quality Control agency as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). Since the Four Corners area is not in ozone non-attainment and the cost economics will not generally justify installation of gas blankets for economic benefit, a voluntary approach is recommended.

B. Indicate the most appropriate agency(ies) to implement: The states.

III. Feasibility of the option

A. Technical: The use of gas blankets for operating tank batteries is technically feasible but requires the tanks to be designed to handle the increased pressures that will result when crude oil/condensate enters the tank, thereby pressurizing the gas blanket. Currently crude oil/condensate tanks are designed as atmospheric tanks and are designed only to withstand 5 psig of internal pressure. API 12F specifies 16 oz of pressure for normal operation and no greater than 24 oz for emergency operations. Using gas blanket technology requires such tanks to withstand about 100 psig, which increases the costs for tanks substantially. As these tanks are under pressure there would be additional operational and safety issues related to proper product transfer and handling. Most transporters are not equipped to handle pressurized product transfers at present.

B. Environmental: The environmental benefits of reduced VOC pollution are well documented.

Differing opinion: If this is considered a candidate control technology, the detailed engineering and economic analyses are needed to evaluate the cost to control relative to other potential control measures.

C. Economic: The use of gas blanket technology for preventing the release of flash and vapor emissions from produced crude oil/condensate are economically feasible for large, centrally located tank batteries where the crude oil/condensate can be piped from numerous wells to a centralized facility. Most wells in the Four Corners area typically produce less than 1 bbl/day of crude oil or condensate so the use of pipelines to transport the crude oil/condensate to a centralized facility is uneconomic.

IV. Background data and assumptions used

1. Individual tank batteries rather than large, centralized tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the minimal daily production volumes (i.e., less than 1 barrel/day).

V. Any uncertainty associated with the option Low.

Differing opinion: HIGH based on feasibility comments above and additional regulatory requirements for pressurized vessels, transport of pressurized product, and added safety processes.

VI. Level of agreement within the work group for this mitigation option

General agreement within working group members that the use of gas blanket technology in the Four Corners areas is economically unfeasible and an unlikely source for voluntary adoption.

Mitigation Option: Installing Floating Roof Tanks on Tanks in the Four Corners Region

I. Description of the mitigation option

This option involves using floating roof tanks on crude oil and condensate tanks so as to prevent the loss of emissions that result from crude oil or condensate stored in the tank. The air quality benefits would be to minimize VOC losses to the atmosphere and if sufficient gas were present, there would be minimal economic benefits. However, the use of floating roof tanks on smaller tanks instead of fixed roof tanks do not reduce the emissions. The emissions actually increase.

Economic burdens are substantial since these units are costly to install and maintain.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement floating roof tanks on tank batteries are envisioned as “voluntary” measures since the feasibility of floating roof tanks in the Four Corners area is negative. At certain facilities in the country where tanks are considerably larger are commonly mandated by the respective Air Quality Control agency as BACT or LAER. The common sizes of tanks in the Four Corners area will not benefit economically or in emission reductions through installation of floating roof tanks. Generally, emissions will increase if floating roofs are installed on these small tanks. Therefore, this mitigation does not have merit for the Four Corners area and is recommended not to be implemented either voluntary or mandatory.

B. Indicate the most appropriate agency (ies) to implement: NMED, Colorado Air Pollution Control Division.

III. Feasibility of the option

A. Technical: The use of floating roof tanks on tank batteries is technically feasible, however, not currently available for smaller sized tanks.

B. Environmental: The environmental benefits of reduced VOC pollution are well documented for larger tanks; however the documentation on smaller tanks with fixed roofs indicates an increase in emissions.

C. Economic: The use of floating tank roofs for preventing the working loss emissions from produced crude oil/condensate is not economically feasible.

IV. Background data and assumptions used

1. Tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the lack of pipeline infrastructure to pipe the fluids directly to refineries.
2. The minimal production levels for most wells make the use of floating tank roofs economically infeasible.

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option.

General agreement within working group members is that the use of floating tank roofs in the Four Corners areas is economically infeasible and an unlikely source for voluntary adoption.

EXPLORATION & PRODUCTION: DEHYDRATORS/SEPARATORS/HEATERS

Mitigation Option: Replace Glycol Dehydrators with Desiccant Dehydrators

I. Description of the mitigation option

Desiccant dehydrators utilize moisture-absorbing salts to remove water from natural gas. Desiccants can be a cost-effective alternative to glycol dehydrators. Additionally, there are only minor air emissions from desiccant systems.

Desiccant dehydrators are very simple systems. Wet gas passes through a “drying” bed of desiccant tablets (e.g., salts such as calcium, potassium or lithium chlorides). The tablets pull moisture from the gas, and gradually dissolve to form a brine solution. Maintenance is minimal - the brine must be periodically drained to a storage tank, and the desiccant vessel must be refilled from time to time. Often, operators will utilize two vessels so that one can be used to dry the gas when the other is being refilled with salt.

Desiccant dehydrators have the benefit of greatly reducing air emissions. Conventional glycol dehydrators continuously release methane, volatile organic compounds (VOC) and hazardous air pollutants (HAP) from reboiler vents; methane from pneumatic controllers; CO₂ from reboiler fuel; and CO₂ from wet gas heaters. The only air emissions from desiccant systems occur when the desiccant-holding vessel is depressurized and re-filled – typically, one vessel volume per week.¹ Some operators have experienced a 99% decrease in CH₄/VOC/HAP emissions when switching over to a desiccant system.²

Other potential benefits of desiccant dehydrators include: reduced ground contamination; reduced fire hazard; low maintenance requirements (because there are no moveable parts to be replaced and maintained); and the elimination of an external power supply.³

Solid desiccants are commonly used at centralized natural gas plants, but glycol dehydrators are still the most popular form of dehydration used in the field.⁴ Most probably this is because there are particular conditions under which desiccant dehydrators work best:

- **The volume of gas to be dried is 5 MMcf/day or less.** Many wells in the San Juan Basin average less than 5 MMcf/day,⁵ so this should not be a constraint to using desiccant systems.
- **Wellhead gas temperature is low (< 59° F for CaCl and < 70° for LiCl).** If the inlet temperature of the gas is too high, desiccants can form hydrates that precipitate from the solution and cause caking and brine drainage problems. It is possible to cool or compress gas to the appropriate temperatures, but this increases the cost of the desiccant system.
- **Wellhead gas pressure is high (> 250 psig for CaCl and >100 psig for LiCl).**

II. Description of how to implement

A. Mandatory or voluntary

Where feasible, it should be mandatory, since it is both cost effective and virtually eliminates air emissions from field dehydrators.

Differing opinion: Cost is prohibitive for replacement of existing systems but applicable for new installations as determined on a case-by-case evaluation.

B. Indicate the most appropriate agency(ies) to implement

Dehydration is not a down-hole issue, therefore, is not the sole purview of the oil and gas commissions. Furthermore, this option relates specifically to minimizing air emissions. Thus, the most appropriate agencies to implement this option would be the environment/health agencies in the different states.

Differing opinion: The Federal area source MACT rules address glycol dehydrators and require controls for those whose size and throughputs justify control. This regulation was carefully considered and evaluated by EPA prior to finalization and should not be exceeded without careful analysis and justification.

III. Feasibility of the option

A. Technical

Desiccant dehydration is currently feasible under certain operating conditions (i.e., temperature and pressure of inlet gas). It may be possible to expand the applicability with add-on technologies (e.g., auto-refrigeration units to chill the inlet gas).⁶

Differing opinion: On March 20, 2007 at the NMOCD Greenhouse Gas meeting held in Santa Fe, NM, an operator stated during his presentation that based on their company's experience with salt dehydration in Wyoming, they are removing all salt dehydrators from service. Although the economics and technical feasibility initially looked very favorable, they have found salt slippage and other operational concerns very problematic with no technical solutions to date. Thus this method of dehydration is currently not as viable for their operations. This technology needs to be thoroughly considered before adoption – although it looks good initially, long-term use has not proven to be sustainable.

B. Environmental

Under some environmental conditions (e.g., high temperatures) this option becomes less feasible. Wastewater by product would need to be handled, disposed of or re-injected. In the CBM areas of Colorado the gas is predominately methane and the gas is relatively dry and requires little dehydration. In this case VOC emissions are minimal. Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required. As a result of the type of production in this region it is likely that dehydration emissions are not significant and the use of such alternative technology may not be warranted.

C. Economic

For new dehydration systems, desiccant systems have been shown to be a lower cost alternative (both for capital and operating costs) than glycol dehydrators.⁷ The payback period to replace an existing glycol dehydrator with a desiccant system has been shown to be less than 3 years.⁸ The economics stated are only valid for a small range of temperature, pressure, and water content combinations. Desiccant dehydration for hot, low pressure, or high water content gas streams is not cost effective when compared to glycol dehydration.

Differing opinion: Increased operational costs for the desiccant, storage, and handling/disposal of wastewater should be factored in to the economics.

IV. Background data and assumptions used See endnotes.

V. Any uncertainty associated with the option Low.

Differing opinion: MEDIUM-HIGH based above comments regarding generation of wastewater, disposal, and recent operational experiences in Wyoming.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other Task Force work groups

Notes:

1. U.S. Environmental Protection Agency. Natural Gas STAR Program. "Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators." p. 5. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf

2. U.S. Environmental Protection Agency. Natural Gas STAR Program. "Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators." p. 1. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf
3. Acor, L. Design Enhancements to Eliminate Sump Recrystallization in Zero-Emissions Non-Regenerative Desiccant Dryer. In: The Tenth International Petroleum Environmental Conference, Houston, TX. November 11-14, 2003 http://ipec.utulsa.edu/Conf2003/Papers/acor_78.pdf
4. Smith, Glenda, American Petroleum Institute, written comments to Dan Chadwick, USEPA/OECA, September 22, 1999. In. EPA Office of Compliance. Oct. 2000. Sector Notebook Project - Profile of the Oil and Gas Extraction Industry. EPA/310-R-99-006. p. 31
5. Lippman Consulting. May 16, 2005. "Production levels increase in San Juan Basin," Energy Quarterly. http://www.businessjournals.com/artman/publish/article_898.shtml
6. U.S. EPA. Natural Gas Star. Replace Glycol Dehydrator with Separators and In-Line Heaters. PRO Fact Sheet No. 204. http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/replaceglycoldehydratorwithseparators.pdf
Auto-refrigeration has been used in other oilfield applications, such as chilling gas to enhance water condensation and separation.
7. U.S. Environmental Protection Agency. Natural Gas STAR Program. "Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators." p. 16. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf
For a system processing 1 MMcf/day natural gas, operating at 450 psig and 47 F:
Total implementation (capital plus installation): \$22,750 (desiccant) vs. \$35,000 (glycol)
Total annual operating costs: \$3,633 (desiccant) vs. \$4,847 (glycol)
8. U.S. Environmental Protection Agency. Natural Gas STAR Program. "Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators." p. 17. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf
This payback period was reported for a glycol dehydrator system that was replaced with a two-vessel desiccant dehydration system.

Mitigation Option: Installation of Insulation on Separators

I. Description of the mitigation option

This option involves modifying existing and installing new separators that are insulated so as to reduce fuel usage. The air quality benefits would be to minimize combustion emissions to the atmosphere (NO_x, CO, NMHC).

Economic burdens are significant but not insurmountable if the cost recovery factor from reduced fuel usage over the anticipated life of the unit shows a positive return on investment.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.

Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement insulated separators and vessels are envisioned as “voluntary” measures since the feasibility of installing insulation on new units or retrofitting existing units must be evaluated for a positive Net Present Value (NPV) or Return on Investment (ROI) in the Four Corners area. If the NPV or ROI meets a company’s investment targets, then utilization of this technology should be encouraged as a best practice. There are no existing mandates by the respective Air Quality Control agencies to require insulated vessels as BACT. Since the Four Corners area is not in ozone non-attainment and the cost economics will not always justify installation of insulation for economic benefit, a voluntary approach is recommended.

B. Indicate the most appropriate agency(ies) to implement: The states.

III. Feasibility of the option

A. Technical: The application of insulation to separators, tanks, or other heated vessels is technically feasible. Currently some companies are insulating newly installed on production separators and larger produced water tanks on a case-by-case basis.

B. Environmental: The environmental benefits of reduced NO_x, CO, and NMHC pollution are well documented.

Differing opinion: It is unclear how much insulation would cut fuel consumption and consequently reduce emissions. The emissions from well-site production units are very small (the units are very small) and not a significant component of the regional NO_x budget. Insulation of these units would make a small reduction in a very small number.

C. Economic: The application of insulation to separators, tanks, or other heated vessels for reducing fuel usage and minimizing combustion emissions from separators, tanks, or other heated vessels are economically feasible where there is payback that meets the respective companies targets for investments (i.e., ROI or NPV). For older units or vessels where the remaining life of the equipment is limited, the economics may not justify the application of insulation. Costs basis and frequency of maintenance and ultimate replacement of both blown and wrapped insulation should be identified.

IV. Background data and assumptions used

Most fired units in the Four Corners area are utilized during the time period from November through March to achieve their objective.

V. Any uncertainty associated with the option (Low, Medium, High) Low.

Differing opinion: High in terms of emission reductions.

VI. Level of agreement within the work group for this mitigation option TBD.

Mitigation Option: Portable Desiccant Dehydrators

I. Description of the mitigation option

Desiccant dehydrators utilize moisture-absorbing salts (e.g., calcium, potassium or lithium chlorides) to remove the water from natural gas.

Glycol dehydrators may be more suitable than desiccant systems in some field gas dehydration situations (e.g., when inlet gas has a high temperature and low pressure). But glycol dehydrators require regulator maintenance for optimal performance. During maintenance periods production wells are either shut-in or vented to the atmosphere (rather than running wet gas into the pipeline). Venting is especially popular for low-pressure wells, because it can be difficult to resume gas flow once they are shut in.

Portable desiccant dehydrators can be brought on-site during glycol dehydrator maintenance (or break-down) periods. This allows the gas to be processed and sent to the pipeline, rather than requiring the well to be shut-in, or the gas to be vented. These portable dehydrators can also be used to capture and dehydrate gas during “green completion” operations.

The benefits of utilizing portable desiccant dehydrators are: the ability to continue producing a well during glycol dehydrator maintenance; the elimination of methane, VOCs and HAPs that would otherwise be vented while glycol dehydrators are being serviced.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary at this point in time. There are technologies that would result in much more significant air emissions reductions that should have higher regulatory priority.

Differing opinion: On March 20, 2007 at the NMOCD Greenhouse Gas meeting held in Santa Fe, NM, an operator stated during his presentation that based on their company’s experience with salt dehydration in Wyoming, they are removing all salt dehydrators from service. Although the economics and technical feasibility initially looked very favorable, they have found salt slippage and other operational concerns very problematic with no technical solutions to date. Thus this method of dehydration is currently not as viable for their operations.

B. Indicate the most appropriate agency(ies) to implement

Environment/Health Departments, which have the responsibility for the regulation of air quality.

III. Feasibility of the option

A. Technical

A portable desiccant dehydrator requires a truck that has been modified to house the dehydrator; and ancillary equipment (e.g., piping) to re-route gas flow from the glycol to the desiccant dehydrator. See the discussion of technical feasibility in the desiccant dehydration option paper – the same comments and issues apply here.

B. Environmental

Desiccant dehydration systems work best under certain gas temperature and pressure conditions. Wastewater by product would need to be handled, disposed of or re-injected. In the CBM areas of Colorado the gas is predominately methane and the gas is relatively dry gas and requires little dehydration. In this case VOC emissions are minimal. Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required. As a result of the type of production in this region it is likely that dehydration emissions are not significant and the use of such alternative technology may not be warranted.

C. Economic

Capital cost of a 10-inch portable desiccant dehydrator is estimated to be greater than \$4,000. Operating costs (e.g., labor, transportation, set-up and decommissioning) are on the order of \$5,000/yr.

Differing opinion: Cost is prohibitive for replacement of existing systems but applicable for new installations as determined on a case-by-case evaluation. Increased operational costs for the desiccant, storage, and handling/disposal of wastewater should be factored in to the economics.

One operator reports that portable desiccant dehydrators are economical when used on gas wells that produced more than 15.6 Mcf/day.

Obviously, a company would get the most economic benefit from owning this equipment if the equipment was kept in continual operation – i.e., moved from one site immediately to another.

IV. Background data and assumptions used

All information in this mitigation option comes from: U.S. EPA. *Portable Desiccant Dehydrators*. PRO Fact Sheet No. 207. Available at: http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/portabledehy.pdf

V. Any uncertainty associated with the option TBD.

Differing opinion: MEDIUM-HIGH based above comments regarding generation of wastewater, disposal, and recent operational experiences in Wyoming.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None at this time.

Mitigation Option: Zero Emissions (a.k.a. Quantum Leap) Dehydrator

I. Description of the mitigation option

Conventional glycol dehydrators route natural gas through a contactor vessel containing glycol, which absorbs water (and VOCs, HAPs) from the gas. Typically, gas-driven pumps are then used to circulate glycol through a reboiler/stripper column, where it is regenerated, then sent back to the contactor vessel. Distillation and reboiling removes VOCs, HAPs and absorbed water from the glycol, and releases these compounds through the “still column” vent as vapor. Conventional glycol dehydrators vent directly to the atmosphere. Add-on technologies, such as thermal oxidizers, can reduce the amount of methane and VOCs that are vented, but result in increased NO_x, particulate matter and CO emissions.¹

Natural gas dehydration is the third largest source of methane emissions and causes more than 80% of the natural gas industry’s annual HAP and VOC emissions.² In the CBM areas of Colorado the gas is predominately methane and the gas is relatively dry gas and requires little dehydration. In this case VOC emissions are minimal. Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required. As a result of the type of production in this region it is likely that dehydration emissions are not significant and the use of such alternative technology may not be warranted.

The zero emissions dehydrator combines several technologies that lower emissions. These technologies eliminate emissions from glycol circulation pumps, gas strippers and the majority of the still column effluent.

- Rather than being released as vapor, the water and hydrocarbons are collected from the glycol still column, and the condensable and non-condensable components are separated from each other. The two primary condensable products are wastewater, which can be disposed of with treatment; and hydrocarbon condensate, which can be sold. The non-condensable products (methane and ethane) are used as fuel for the glycol reboiler, instead of releasing them to the atmosphere.
- A water exhauster is used to produce high glycol concentrations without the use of a gas stripper.
- Methane emissions are further reduced by using electric instead of gas-driven glycol circulation pumps.

Benefits of this technology include:

- Elimination of methane emissions.³
- Elimination of virtually all VOCs (reduction from multiple tons per year to pounds per year.⁴
- Has a HAP destruction efficiency of greater than 99%.⁵
- Reduces emissions of particulate matter, sulfur dioxide, NO_x or CO emissions (these compounds are emitted when thermal oxidation, a competing method of reducing glycol dehydrator VOC emissions, is used).
- Eliminates the Kimray pump, which is typically used to circulate glycol. Kimray pumps require extra gas (which is eventually vented to the atmosphere) for pump power.⁶
 - Significantly reduces fuel requirements for glycol reboiler. Natural gas that was used for this purpose can now be sent to market.
 - Results in collection of condensate, which can be sold.

II. Description of how to implement

A. Mandatory or voluntary

The zero emissions dehydrator system offers incredible reductions in emissions. States that are experiencing air quality problems could make this a mandatory technology, and achieve large reductions in VOC, HAP and methane emissions.

Differing opinion: Previous statement requires supporting documentation and quantification of ‘trade-off’ pollutants.

B. Indicate the most appropriate agency(ies) to implement

Dehydration is not a down-hole issue, therefore, is not the sole purview of the oil and gas commissions. Furthermore, this option relates specifically to minimizing air emissions. Thus, the most appropriate agencies to implement this option would be the environment/health agencies in the different states.

III. Feasibility of the option

A. Technical

The operation of the glycol circulation pump requires electric utilities or an engine generator set. The use of electric pumps (rather than fossil fuel driven pumps) will minimize NO_x, CO, CO₂, SO₂ emissions at the wellhead, but will result in some emissions at electrical generation source (e.g., coal-fired power plant).

Zero emissions dehydrators can be newly installed, and existing dehydrators can be retrofitted by modifying the gas stream piping and using a 5 kW engine-generator for electricity needs.⁷ This requires a fuel or power source, for which associated emissions need to be quantified.

B. Environmental

Environmental benefit for this mitigation option needs to be defined.

C. Economic⁸

Capital costs of a zero emissions dehydrator are similar to the costs of installing a conventional dehydrator equipped with a thermal oxidizer (>\$10,000). Operating and Maintenance costs are greater than \$1,000 per year, but lower than the maintenance costs for conventional glycol dehydrators.

If operators were to install zero emissions dehydrators, EPA estimates that the payback to occur in less than a year.

Differing opinion: This presumes the ability to recover the hydrocarbons for sales – which is not without significant challenges and technical difficulties.

IV. Background data and assumptions used

The calculations of methane, VOC and HAP emissions from the zero emissions dehydrator were based on a dehydrator that processed 28 MMcf/day.⁹ Other assumptions are contained in the endnotes.

If we had emissions data for glycol dehydrators from the San Juan Basin, we could provide a more accurate (and basin-specific) comparison of methane, VOC and HAP emissions from conventional dehydrators versus emissions from zero emissions dehydrators.

V. Any uncertainty associated with the option TBD.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None at this time.

Notes:

1. Permit renewal application by Centerpoint Energy Gas Transmission Co. to Louisiana Department of Environmental Quality. AI# 26802. March, 2005. Available at: <http://www.deq.louisiana.gov/apps/pubNotice/show.asp?qPostID=2335&SearchText=centerpoint&startDate=1/1/2005&endDate=7/6/2006&category=>

The application includes estimated emissions scenarios for controlling glycol dehydrator still column vent emissions with or without thermal oxidation.

2. McKinnon, H.W. and Piccot, S.D. 2003. "Emissions control of criteria pollutants, hazardous pollutants, and greenhouse gases, Natural Gas Dehydration, Quantum Leap Dehydrator." Environmental Technology Verification Program, Joint Verification Statement. U.S. EPA and Southern Research Institute. Available at: http://www.epa.gov/etv/pdfs/vrvs/03_vs_quantum.pdf
3. *ibid.*
4. Rueter, C.O., Reif, D.L. and Myers, D.B. 1995. Glycol dehydrator BTEX and VOC emissions testing results at two units in Texas and Louisiana. U.S. EPA Air and Energy Engineering Research Laboratory. Project No. EPA/600/SR-95/046.
A study of two glycol dehydrators, processing 3.6 and 4.9 million standard cubic feet of gas per day, were found to have VOC emissions of approximately 19 and 37 tons of VOC/year, respectively. Tests run on the Zero Emissions Dehydrator, processing 28 million standard cubic feet of gas per day, resulted in average emissions of 0.0003 lb/h (2.6 lbs/yr). This is a dramatically lower amount of VOC emissions than conventional glycol dehydrators.
5. McKinnon, H.W. and Piccot, S.D. 2003. (See Note 2)
6. Fernandez, R., Petrusak, R., Robins, D. and Zavodil, D. June, 2005. "Cost-effective methane emissions reductions for small and midsize natural gas producers," Journal of Petroleum Technology. Available at: http://www.icfi.com/Markets/Environment/doc_files/methane-emissions.pdf
7. U.S. EPA. "Zero emissions dehydrators," PRO Fact Sheet No. 206. Available at: http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/zeroemissionsdehy.pdf
8. All of the economic information comes from: U.S. EPA. (see Note 7)
9. McKinnon, H.W. and Piccot, S.D. 2003. (See Note 2)

Mitigation Option: Venting versus Flaring of Natural Gas during Well Completions

I. Description of the mitigation option

Both venting and flaring of natural gas result in the release of greenhouse gases, hazardous air pollutants (HAPs) and others.

The venting of natural gas primarily releases methane, a greenhouse gas. Depending on the composition of the gas, venting will release other hydrocarbons such as ethane, propane, butane, pentane and hexane. In some locations, natural gas contains the EPA-designated HAPs benzene, toluene, ethyl benzene and xylenes (BTEX). Both hexane (also a HAP) and the BTEX compounds are present in San Juan Basin natural gas, typically accounting for 0.3 - 0.6 % of the natural gas composition.¹

Differing opinion: This is only true for the conventional production. Coal bed methane does not contain appreciable amounts of VOCs or HAPs. Depending on the formation, natural gas may also contain nitrogen, carbon dioxide or sulfur compounds, such as hydrogen sulfide (H₂S), which is a highly toxic gas. 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 hydrogen sulfide.²

Flaring is used as a means of converting natural gas constituents into less hazardous and atmospherically reactive compounds. The main purpose for flaring is for process safety reasons. Flaring is required when completing a well for two reasons: (1) the initial gas and liquids produced by most wells does not meet the gas gatherer's (pipeline's) quality requirements, and (2) the flare is the primary safety device in the event of an overpressure or equipment failure. The objective for both industry and the public is to minimize flaring where possible for both environmental and economic reasons. The assumption is that combustion processes associated with flares efficiently converts hydrocarbons and sulfur compounds to relatively innocuous gases such as CO₂, SO₂, and H₂O.

While industrial flares associated with processes such as refineries have the potential to be highly efficient (e.g., 98-99%), the few studies that have been conducted on oil and gas "field flares" have found much lower efficiencies (62-84%).³ Fields flares without combustion enhancements (e.g., knockout drums to collect liquids prior to entering the flare; flame retention devices; pilots) have a much lower efficiency compared to properly designed and operated industrial flares.⁴ Other factors, such as improper liquids removal,⁵ low heating value of the fuel,⁶ flow rate of gas,⁷ and high wind speeds,⁸ also decrease the combustion efficiency of flares.

Differing opinion: The one study cited is the only flare study that found low destruction efficiencies when burning production type gas streams. A number of other studies have confirmed destruction efficiencies >98% - which is the EPA guidance. A cooperative study, known as the international flare consortium study, is underway now and is testing destruction efficiencies across a wide range of gas types, flare types, and conditions.

There is a dearth of information on combustion efficiencies for flares used during well completion events, but given the fact that these flares are more rudimentary than industrial or even solution gas flares, it is highly possible that they have even lower combustion efficiencies.

Differing opinion: There are a number of very well done flare studies published.

When flares burn inefficiently, a host of hydrocarbon by-products that include highly reactive VOCs and polycyclic aromatic hydrocarbons, may be formed.⁹ Leahey et al. (2001) found more than 60 hydrocarbon by-products, including known carcinogens such as benzene, anthracene and benzo(a)pyrene, downwind of a natural gas flare estimated to be operating at 65% combustion efficiency.¹⁰ The inefficient burning of hydrocarbons also produces soot (particulate matter).¹¹ Additionally, nitrogen oxides are formed during the combustion process, even if the flare gas does not contain nitrogen.¹²

Differing opinion: The one study cited is the only flare study that found low destruction efficiencies when burning production type gas streams. A number of other studies have confirmed destruction efficiencies >98% - which is the EPA guidance. A cooperative study, known as the international flare consortium study, is underway now and is testing destruction efficiencies across a wide range of gas types, flare types, and conditions.

See the Endnotes for a table that summarizes the potential health and environmental effects related to compounds released during flaring and venting.¹³

Differing opinion: Not having access to the original table(s), it appears that errors may have occurred when it was adapted given the unwarranted combination of gas constituents and combustion products in one table and some obvious flaws (i.e., VOCs, SO₂ and NO_x contributing to particulate pollution but not aggravating respiratory conditions).

Flares operated during well completion activities handle enormous volumes of gas, which is either vented or flared over a short period of time. The amounts of HAPs and VOCs produced during a typical well completion in Wyoming have been calculated. It has been estimated that a single well completion event, which lasts an average of 10 days, releases:

- 115 tons of VOCs, and 4 tons of HAPs (assumption: 100% venting); or
- 86 tons VOCs, and 3 ton HAPs (assumption: half of the gas is flared per completion, and the flare operates at 50% efficiency).¹⁴

Differing opinion: Many completions in Wyoming – particularly those with gas flow rates in the 4 MMSCF/day range suggested above – are completed using flareless completion techniques which significantly reduces volume flared (75 to 90% reduction). However, use of these techniques is limited to those areas where the reservoir pressure is high enough to clean up the well and get the gas into the pipeline.

While it is clear that flaring reduces the volume (mass) of VOCs and HAPs, questions remain, such as: what are the particular VOC and HAP compounds released during both venting and flaring; what are the concentrations of these compounds in ambient air;¹⁵ and can well completion flares somehow be designed (e.g., better liquid removal, lower gas flow rates going to the flare) to more effectively destroy hazardous compounds.

For a true assessment of the relative benefits of flaring vs. venting (especially with respect to human health), there is a need for a better assessment of venting/flaring emissions from well completions in the San Juan Basin. This assessment should determine both volumes of emissions, and provide a characterization of VOCs, HAPs and other compounds emitted (volumes and species) during well completion venting and flaring.

II. Description of how to implement

Using methods similar to those used in Wyoming, calculations could be performed to estimate the amount of VOCs and HAPs released from flaring and venting during well completion events in the San Juan Basin. Information requirements include:

- volume of gas released (vented or flared) per well completion
- VOC and HAP weight % of the natural gas
- estimates of combustion efficiency of flares
- estimates of how often flares are extinguished (resulting in venting of gas)

Monitoring downwind of sites that are flaring and/or venting is needed, to better characterize concentrations and species of VOCs and HAPs, as well as other flaring by-products.

A. Mandatory or voluntary

Initially, it could be a voluntary initiative, but if that does not produce data or results there may need to be mandatory reporting and monitoring requirements.

B. Indicate the most appropriate agency(ies) to implement

State oil and gas commissions could require the reporting of well completion emissions volumes; and environment/health departments would be the appropriate agencies to require monitoring of venting and flaring emissions.

III. Feasibility of the option

A. Technical

Emissions volumes from well completions have been determined for Wyoming, so presumably it is technically feasible to determine volumes for the San Juan Basin. If the data do not exist, perhaps the monitoring work group could work with industry to calculate or develop estimates of these volumes specific to the San Juan Basin.

Researches in Alberta have been able to determine combustion by-products using on-site analytical equipment or through absorbent samplers for confirmatory analyses by combined gas chromatography/mass spectrometry. Flare combustion efficiency were then calculated using a carbon mass balance of combustion products identified in the emissions. See Strosher (1996), Endnote 4.

B. Environmental

None.

C. Economic

Emissions volumes from well completions: low cost.

The identification of compounds emitted during venting and combustion: unknown.

IV. Background data and assumptions used See Endnotes Section.

V. Any uncertainty associated with the option

High uncertainty: depends on willingness of industry and regulators to undertake the necessary data collection.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None.

Notes:

1. Proportions calculated based on data from: Mansell, G.E. and Dinh, T. (ENVIRON International). September 2003. Emission Inventory Report - Air Quality Modeling Analysis For The Denver Early Action Ozone Compact: Development of the 2002 Base Case Modeling Inventory. p. 3-5.

<http://apcd.state.co.us/documents/eac/2002%20Modeling%20EI.pdf>

Table 3-5. Average gas profiles (% composition) by formation for the San Juan Basin

	Mesa Verde	Dakota	Pictures Cliffs	Gallup	
Nitrogen	0.212	1.603	0	0.965	
Carbon Dioxide	1.388	1.034	1.403	0.639	
Methane	84.372	74.979	87.736	76.944	
Ethane	8.221	12.163	6.373	10.823	
Propane	3.19	6.488	2.651	6.552	
Butanes	1.432	2,532	1,148	2.551	
Pentanes	0.727	0.765	0.418	0.948	
Hexanes	0.459	0.437	0.270	0.578	
Benzene	0.0145	0.016	0.003		
Toluene	0.00706	0.003	0.0014		
Ethyl Benzene	0.00037	0.0001	0.0002		
Xylene	0.002	0.0006	0.001		
Calculated VOC and HAP content (not in original chart)					Average for all formations
HAPS (BTEX + hexane)	0.483	0.457	0.276	0.578	0.4483
VOCs (C1-C4)	97.94	96.93	98.33	97.82	97.753

2. Hewitt, J. (Bureau of Land Management). 2005. "H2S Occurrences San Juan Basin," a presentation at Hydrogen Sulfide: Issues and Answers Workshop. http://octane.nmt.edu/sw-pttc/proceedings/H2S_05/BLM_H2S_SanJuanBasin.pdf

3. Strosher, M. 1996. Investigations of Flare Gas Emissions in Alberta. Alberta Research Council, November 1996.

Strosher (1996) found flaring efficiencies of 62-71% and 82-84% for sweet and sour gas flares, respectively. The sweet gas had a higher liquid hydrocarbon content than the sour gas being flared. Leahy et al. (2001, citation in Endnote 9) observed flare efficiencies of $68 \pm 7\%$ at sweet and sour gas flares in Alberta.

4. Seebold, J., Davis, B., Gogolek, P., Kostiuk, L., Pohl, J., Schwartz, B., Soelberg, N., Strosher, M., and Walsh, P. 2003. "Reaction Efficiency of Industrial Flares: the perspective of the past." International Flare Consortium, Combustion Canada '03 Paper. http://www.nrcan.gc.ca/es/etb/cetc/ifc/id4_e.html

5. Russell, J. and Pollack, A. (ENVIRON International). 2005. Final Project Report: Oil And Gas Emission Inventories For The Western States. Report prepared for the Western Governors' Association. Appendix A, Wyoming Emission Factor Documentation. p. A-2.

http://www.wrapair.org/forums/ssjf/documents/eiccts/OilGas/WRAP_Oil&Gas_Final_Report.122805.pdf
When liquid content is too high, flares don't or won't ignite.

6. Kostiuk, L.W., M.R. Johnson & R.A. Prybysh. 2000 "Recent Research on the Emission from Continuous Flares," Paper presented at CPANS/PNWIS-A&WMA Conference (Banff, Alberta, April 10-12). Cited in: Seebold et al. (2003).

7. Strosher, M. 1996. Investigations of Flare Gas Emissions in Alberta. Alberta Research Council, November 1996. p. 85.

Combustion efficiencies decreased from 70.6% (flow rate of 1 m³/min) to 67.2 % (flow rate of 5-6 m³/min) for sweet gas being flared at an oil tank battery in Alberta.

Increasing the flow increased the volatile hydrocarbons by about 33%, and the non-volatiles by three times the concentrations found in the lower volume flow.

8. Leahy, Douglas M., Preston, Katherine and Strosher, Mel. 2001. Theoretical and Observational Assessments of Flare Efficiencies," Journal of the Air & Waste Management Association. Volume 51. p. 1615

"It has been shown, as well, that flaring can be efficient only at low wind speeds because the size of the flare flame, which is an indicator of flame efficiency, decreases with increasing wind speed. Therefore, the flaring process could routinely result, during periods of moderate to high wind speeds, in appreciable quantities of products of incomplete combustion such as anthracene and benzo(a)pyrene, which can have adverse implications with respect to air quality."

9. Seebold, J., Gogolek, P., Pohl, J., and Schwartz, R. 2004. "Practical implications of prior research on today's outstanding flare emissions questions and a research program to answer them," Paper presented at the AFRC-JFRC 20004 Joint International Combustion Symposium, Environmental Control of Combustion Processes: Innovative Technology for the 21st Century. (Oct. 10-13, 2004; Maui, Hawaii). http://www.nrcan.gc.ca/es/etb/cetc/ifc/id12_e.html

For example, during the 1990s, research conducted as part of the Petroleum Environmental Research Forum's project 92-19 "The Origin and Fate of Toxic Combustion By-Products in Refinery Heaters" showed that even when burning laboratory grade methane "pure as the drifted snow" traces of higher molecular weight compounds not originally present in the fuel are found in the flue gas (e.g., ethylene, propylene, butadiene, formaldehyde, benzene, benzo(a)pyrene and other hydrocarbons in the gas phase up through coronene).

Seebold, et al. also report that, "the external combustion of hydrocarbon gas mixtures by any means, including flaring, literally manufactures and subsequently emits to the atmosphere traces of all possible molecular combinations of the elemental constituents present either in the fuel or in the air including the ozone precursor highly reactive volatile organic compounds (HRVOCs) and the carcinogenic hazardous air pollutants (HAPs).

10. Leahey, Douglas M., Preston, Katherine and Strosher, Mel. 2001. "Theoretical and Observational Assessments of Flare Efficiencies," Journal of the Air & Waste Management Association. Volume 51. p.1614. <http://www.awma.org/journal/pdfs/2001/12/Leahey.pdf>

Speciated data for combustion products observed downwind of the sweet gas flare using solvent extraction methods.

Product	Volume (mg/m3)	Product	Volume (mg/m3)
Nonane	0.41	9h-fluorene, 3-methyl-	3.05
Benzaldehyde (acn)(dot)	0.53	Phenanthrene	10.01
Benzene, 1-ethyl-2-methyl-	0.13	Benzo(c)cinnoline	2.06
1h-indene, 2,3-dihydro-	0.34	Anthracene	42.11
Decane	1.72	1h-indene, 1-(phenylmethylene)-	1.94
Benzene, 1-ethynyl-4-methyl-	9.83	9h-fluorene, 9-ethylidene-	0.89
Benzene, 1,3-diethenyl-	1.27	1h-phenalen-1-one	1.86
1h-indene, 1-methylene-	0.28	4h-cyclopenta[def]phenanthrene	3.50
Azulene	21.20	Naphthalene, 2-phenyl-	1.98
Benzene, (1-methyl-2-cyclopropen-1-yl)-	11.47	Naphthalene, 1-phenyl-	1.82
1h-indene, 1-methyl-	1.66	9,10-anthracenedione	0.94
Naphthalene (can)(dot)	99.39	5h-dibenzo[a,d]cycloheptene, 5-methylene-	0.75
Benzaldehyde, o-methyloxime	0.27	Naphthalene, 1,8-di-1-propynyl-	1.14
1-h-inden-1-one, 2,3-dihydro-	0.74	Fluoranthene 51.35 Benzene, 1,1'-(1,3-butadiyne-1,4-diyl)bis-	2.07

Naphthalene, 2-methyl-	9.25	Pyrene	32.37
Naphthalene, 1-methyl-	6.18	11h-benzo[a]fluorene	2.25
1h-indene, 1-ethylidene-	1.22	Pyrene, 4-methyl-	9.13
1,1'-biphenyl	58.70	Pyrene, 1-methyl-	8.38
Naphthalene, 2-ethyl-	1.87	Benzo[ghi]fluoranthene	10.16
Biphenylene	42.81	Cyclopenta[cd]pyrene	29.77
Naphthalene, 2-ethenyl-	7.32	Benz[a]anthracene	17.33
Acenaphthylene	7.15	Chrysene	2.12
Acenaphthene	2.93	Benzene, 1,2-diphenoxy-	1.94
Dibenzofuran	0.88	Methanone, (6-methyl-1,3-benzodioxol-5-yl)phenyl-	0.95
1,1'-biphenyl, 3-methyl-	0.31	Benzo[e]pyrene	0.71
1h-phenalene	21.01	Benzo[a]pyrene	1.03
9h-fluorene	41.09	Perylene	0.62
9h-fluorene, 9-methyl-	1.07	Indeno[1,2,3-cd]pyrene	0.15
Benzaldehyde, 4,6-dihydroxy-2,3-dimethyl	1.16	Benzo[ghi]perylene	0.26
9h-fluorene, 9-methylene-	1.07	Dibenzo[def,mno]chrysene	0.15
		Coronene	0.08

11. U.S. Environmental Protection Agency. 2000. Office of Air Quality Planning and Standards. "Industrial Flares," AP-42 Fifth Edition. Vol. 1: Stationary Point and Area Sources. p. 13.5-3.

Tendency to smoke or make soot is influenced by fuel characteristics and by amount and distribution of oxygen in the combustion zone. All hydrocarbons above methane tend to soot. Soot from industrial flares is eliminated by adding steam or air.

Soot emissions factors developed by EPA for industrial flares are: non-smoking flares, 0 micrograms per liter ($\mu\text{g/L}$); lightly smoking flares, 40 $\mu\text{g/L}$; average smoking flares, 177 $\mu\text{g/L}$; and heavily smoking flares, 274 $\mu\text{g/L}$.

12. K.D. Siegel. 1980l. Degree of Conversion of Flare Gas in Refinery High Flares. Dissertation. University of Karlsruhe, Germany. Cited in: USEPA Office of Air Quality Planning and Standards. 2000. "Industrial Flares," AP-42 Fifth Edition. Volume 1: Stationary Point and Area Sources. p.13.5-5.

Even waste gas that does not contain nitrogen compounds form NO. It is formed either by fixation of atmospheric nitrogen with oxygen, or by the reaction between hydrocarbon radicals and atmospheric N by way of intermediate states, HCN, CN and OCN.

13. Health and Environmental Effects of Chemicals Released During Venting and Flaring.

	VOCs	SO2	NOx	CO	PAHs	H2S	HAPs	SMO KE/ SOOT
Contributes to particulate pollution that can cause respiratory illness, aggravation of heart conditions and asthma, permanent lung damage and premature death.	FLAR ING	FLAR ING	FLAR ING					FLAR ING
Aggravates respiratory conditions						VENT ING		
								FLAR ING

	VOCs	SO2	NOx	CO	PAHs	H2S	HAPs	SMO KE/ SOOT
Can cause health problems such as cancer	VENT ING						VENT ING	
	FLAR ING				FLAR ING		FLAR ING	
Can cause reproductive, neurological, developmental, respiratory, immune system, and other health problems.							VENT ING	
							FLAR ING	
Reacts with other chemicals leading to ground-level ozone and smog, which can trigger respiratory problems	VENT ING							
	FLAR ING		FLAR ING					
Reacts with common organic chemicals forming toxins that may cause bio-mutations								
			FLAR ING					
Affects cardiovascular system and can cause problems within the central nervous system						VENT ING		
Causes haze that can migrate to sensitive areas such as National Parks	VENT ING							
	FLAR ING	FLAR ING	FLAR ING	FLAR ING				FLAR ING
Contributes to global warming	VENT ING							

Adapted from: EPA Office of Inspector General. 2004. EPA Needs to Improve Tracking of National Petroleum Refinery Program Progress and Impacts. Appendix D.

14. Russell, J. and Pollack, A. (ENVIRON International). 2005. Final Project Report: Oil And Gas Emission Inventories For The Western States. Report prepared for the Western Governors' Association. Appendix A, Wyoming Emission Factor Documentation. p. A-2.

http://www.wrapair.org/forums/ssjf/documents/eiccts/OilGas/WRAP_Oil&Gas_Final_Report.122805.pdf

15. Strosher, M. 1996. Investigations of Flare Gas Emissions in Alberta. Alberta Research Council, November 1996. p. 28.

Strosher measured concentrations of hydrocarbon compounds emitted from sweet and sour solution gas flares in Alberta, and then predicted ground-level concentrations of HAPs at various locations around the well location. Predicted values of some polycyclic aromatic hydrocarbons in the vicinity of sweet and sour gas flares were comparable to concentrations found in large industrial cities, while predicted values of hazardous VOCs released during flaring were below ambient air quality standards.

Mitigation Option: Co-location/Centralization for New Sources

I. Description of the mitigation option

This mitigation option would involve co-locating and/or centralizing new oil/gas field facilities, including roads, well pads, utilities, pipelines, compressors, power sources and fluid storage tanks, wherever possible, to reduce surface impacts, fugitive dust, engine emissions and gas field traffic.

In general, co-location and/or centralization of new facilities would result in overall reductions in surface disturbance, vehicular traffic, and number of facilities. Potential benefits from this strategy include fugitive dust reduction (due to decreased traffic and less overall new surface disturbance), vehicle emission reductions, reduced road maintenance, safer roads as a result of decreased traffic, and oil/gas field engine emission reductions. The potential for reduced engine emissions is due in part to lowering cumulative horsepower requirements by using larger, more efficient engines, and in part to groups of smaller engines with relatively high emission rates per hp/hr being replaced by fewer, larger engines with relatively low emission rates per hp/hr. Implementation costs for this mitigation option would fall exclusively on the energy companies, but such costs could be partially offset by the economic benefits of having fewer facilities to construct, maintain and ultimately reclaim.

Tradeoffs include increased impacts at co-located/centralized sites. Co-locating well bores on a single pad results in larger pad sizes that may not fit well with pre-existing conditions. Centralizing facilities would increase vehicle emissions locally and potentially produce local air quality, noise, visual and traffic safety issues. Additionally, aggregating produced water in one location increases the potential for a catastrophic release.

II. Description of how to implement

A. This mitigation option should be implemented on a voluntary basis, with the approach emphasized by the appropriate regulatory agency during the planning and permitting processes for oil/gas field facilities and utility corridors (pipelines, power lines, etc.). Consideration should be given to economic and environmental impacts, as well as current and future land management activities. Ideally, oil/gas field operators and regulatory agencies would coordinate on a regular basis to identify development plans that minimize new construction and maximize efficiencies. Cooperation between operators in the same development area would make this option even more effective, but multiple economic and regulatory constraints exist that make such coordination difficult.

B. State and Federal lands and minerals management agencies would be able to emphasize this approach at various stages of the planning and permitting process. In addition, State and Federal air regulatory agencies could emphasize this approach if multiple air quality permit applications are submitted concurrently for the same general area.

III. Feasibility of the option

A. Technical: The technology exists today to implement this mitigation option. This option is best suited for areas of known or high potential for economic oil/gas field production. This option can be implemented most effectively when planning for oil/gas field- or lease-wide development activities, such as in-fill drilling and plans of development for multiple wells.

B. Environmental: Co-location and/or centralization of new facilities would generally have numerous environmental benefits.

C. Economic: Economic feasibility of this option will vary on a project-level basis. Higher initial costs may be offset by overall cost reductions due to fewer facilities to construct, operate and reclaim. Additional cost savings may result because co-located/centralized facilities can be more efficient than dispersed facilities.

IV. Background data and assumptions used

This option is best suited for areas with existing or high potential for economic gas/oil field production.

V. Any uncertainty associated with the option

Low. While implementation of this option may cause greater noise, emission, and visual impacts at fewer, co-located/centralized locations, the overall effect would be a reduction in oil/gas field environmental impacts.

VI. Level of agreement within the work group for this mitigation option Unknown at this time

VII. Cross-over issues to the other source groups

Road-related impacts are an element of this mitigation option being looked at by the Other Sources Workgroup. Two other mitigation strategies (Optimization/Centralization and Reduced Truck Traffic by Centralizing Produced Water Storage Facilities) look at the compression and produced water facets of this mitigation option in greater detail and are presented in the Oil and Gas section of this Task Force Report. Assistance from the Cumulative Effects work group to quantify potential dust, vehicle traffic and overall emission reductions resulting from co-location and/or centralization would be helpful.

VIII. References

http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices.html

<http://www.westgov.org/wga/initiatives/coalbed/>

http://bogc.dnrc.state.mt.us/website/mtcbm/webmapper_cbm_info_res.htm

Mitigation Option: Control Glycol Pump Rates

I. Description of the mitigation option

Most dehydration systems use triethylene glycol (TEG) as the absorbent fluid to remove water from natural gas. As TEG absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). As TEG is regenerated through heating in a reboiler, absorbed methane, VOCs, and HAPs are vented to the atmosphere with the water, wasting gas and money. The amount of methane absorbed, and used as assist gas for Kimray type pumps, and vented is directly of the TEG Dehydrator, but continue to circulate TEG at rates two or three times higher than necessary, resulting in little improvement in gas moisture quality but much higher methane emissions and fuel use. Reducing TEG circulation rates reduce methane emissions at negligible cost.

Economic burdens are minimal since this practice simply requires the pump rate to be manually adjusted.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of lower TEG circulation rates should be “voluntary” since the measure would enhance recovery of natural gas and reduce emissions. Companies should be receptive to voluntarily implement this measure.

B. Indicate the most appropriate agency(ies) to implement: The state Air Quality Divisions should communicate this information.

III. Feasibility of the option

A. Technical: Controlling TEG circulation rates are technically feasible since it can be achieved by manually setting the pump rate.

B. Environmental: The environmental benefits of reduced VOC pollution are well documented. The reduction of methane, a greenhouse gas, can also be documented. Quantification of emission reductions can be achieved through the use of the GLYCALC model.

Due to the low field pressures in the San Juan basin area, most field dehydrators have been removed and dehydration is done at central facilities rather than dispersed locations. Due to this, this option will have very limited applicability and emission reductions associated with it.

C. Economic: The benefits can be quantified by the amount of methane and VOC that is not emitted to the atmosphere and rather sold as product.

IV. Background data and assumptions used

A. Gas production fields experience declining production as pressure is drawn-off the reservoir. Wellhead glycol dehydrators and their TEG circulation rates are designed for the initial, highest production rate, and therefore, become over-sized as the well matures. It is common that the TEG circulation rate is much higher than necessary to meet the sales gas specification for moisture content.

B. The methane emissions from a glycol dehydrator are directly proportional to the amount of TEG circulated through the system. The higher the circulation rate, the more methane, is vented from the regenerator. Over-circulation results in more methane emissions without significant and necessary reduction in gas moisture content.

C. Operators can reduce the TEG circulation rate and subsequently reduce the methane emissions rate, without affecting dehydration performance or adding any additional cost.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option

Although a general discussion of this option has not occurred between the working group members, it is doubtful a disagreement about controlling TEG circulation rates would occur.

Source of Information: “Optimize Glycol Circulation and Install of Flash Tank Separators in Dehydrators”, U.S. EPA Natural Gas Star Program.

Mitigation Option: Combustors for Still Vents

I. Description of the mitigation option

Most dehydration systems use triethylene glycol (TEG) as the absorbent fluid to remove water from natural gas. As TEG absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). The TEG is then distilled to strip water and consequently VOC from the TEG. Vapors and/or liquids in the still vent are typically greater than 90% volume water, with the balance being hydrocarbons along with small quantities of carbon dioxide and nitrogen. The still vent column is typically released to the atmosphere that includes emissions of hydrocarbons. It is important to note that gas composition is an important consideration in determining the need to install flares. Some natural gas, such as coalbed methane gas contains little, if any VOC component, and would not result in VOC emissions.

In order to reduce these emissions, combustion devices can be installed to combust hydrocarbon emissions, including VOCs, instead of venting them to the atmosphere. The combustion technology typically consists of an enclosed “flare/burner.” It does require a condenser and separator upstream of the combustion device to avoid liquid hydrocarbons routed to the combustion device.

II. Description of how to implement

A. Mandatory or voluntary: The requirement for control of emissions from glycol dehydrators is included in the EPA’s area source *Onshore Natural Gas Processing* MACT rules that have been proposed/promulgated. After careful analysis, EPA set emission and throughput based criteria to trigger these control requirements. Any control at lower emission or throughput rates should be voluntary.

B. Indicate the most appropriate agency(ies) to implement: The state Air Quality Divisions should develop the regulatory program to administer this program.

III. Feasibility of the option

A. Technical: Installing condensers and combustion devices to control emissions from dehydrator still vents is technically feasible since it is already being applied in various locations where controls of these emissions have been mandated.

B. Environmental: The environmental benefits of reduced VOC emissions are well documented. The reduction of methane, a greenhouse gas, can also be documented. Actual benefits are dependent on the amount and composition of the gas being dehydrated and are highly variable. Little benefit is expected for the San Juan basin due to the lack of field dehydration.

C. Economic: Costs are for a typical condenser and smokeless combustion chamber large enough to service a dehydrator in Wyoming are about \$35,000 installed. There are no revenues from the gas as it is destroyed through combustion, and there is a fuel cost of about \$1,800 per year for each pilot (at \$3 per Mcf of gas).

IV. Background data and assumptions used Wyoming oil and gas presumptive BACT guidance.

V. Any uncertainty associated with the option Low where applicable.

VI. Level of agreement within the work group for this mitigation option

Although a general discussion of this option has not occurred between the working group members, it is unknown about the degree of acceptance regarding the use of combustors for still vents.

Source of Information: “Install Flares”, PRO Fact Sheet No. 905, U.S. EPA Natural Gas Star Program. Gas Research Institute, Control Device Monitoring of Glycol Dehydrators; Condenser Efficiency Measurements and Modeling, 1997.

EXPLORATION & PRODUCTION: WELLS

Mitigation Option: Installation and/or Optimization of a Plunger Lift System

I. Description of the mitigation option

Overview

In mature gas wells, the accumulation of fluids in the well-bore can impede and sometimes halt gas production. Fluids are removed and gas flow maintained by removing accumulated fluids through the use of artificial lift (such as a beam pump) or enhanced fluid lift treatments or techniques, such as plunger lifts, velocity strings, swabbing, soap injection, or venting the well to atmospheric pressure (referred to as “blowing down” the well). Fluid removal operations, particularly well blow-downs, may result in substantial methane and associated VOC emissions to the atmosphere.

Installing a plunger lift system can be a cost-effective alternative for removing liquids on wells where the well-bore configuration, pressure profiles, and production characteristics enable its application. Plunger lift systems have the additional benefit of potentially increasing production, as well as significantly reducing methane and associated VOC emissions associated with blow-down operations. A plunger lift uses gas pressure buildup in a well to lift a column of accumulated fluid out of the well. The plunger lift system helps to maintain gas production and may reduce the need for other remedial operations.

Air Quality and Environmental Benefits

The installation of a plunger lift system serves as an interim well-bore deliquification methodology for the period between natural flowing lift and full artificial lift and can yield environmental and production benefits while reducing well blow-downs and their associated emissions. The extent and nature of these benefits depend on the individual well characteristics and the method of plunger lift control and operation.

New automation systems and control capabilities can improve plunger lift system optimization, monitoring, and control. For example, technologies such as programmable logic controllers and remote transmitter units can allow operators to control plunger lift systems through control algorithms or remotely, without regular field visits. These systems can offer enhanced plunger lift operation and effectiveness versus older plunger control systems.

By reducing the need for well-bore blow-down, plunger lift systems can lower emissions. Reducing repetitive remedial treatments and well work-over may also reduce methane and associated emissions. Natural Gas STAR partners have reported annual gas savings averaging 600 Mcf per well by avoiding blow-down and an average of 30 Mcf per year by eliminating or reducing well work-overs.

Economics

Lower capital and operational cost versus installing full artificial lift equipment (such as a beam pump). The costs of installing and maintaining a plunger lift are generally lower than the cost to install and maintain artificial lift equipment.

Lower well maintenance and fewer remedial treatments. Overall well maintenance costs are reduced because periodic remedial treatments such as swabbing or well blow-downs are reduced or no longer needed with plunger lift systems.

More effective well-bore deliquification and continuous production may improve gas production rates and increase efficiency. With proper optimization and control, plunger lift systems can also conserve the well’s lifting energy and increase gas production. Regular fluid removal allows the well to produce gas

continuously and helps prevent fluid loading that periodically halts gas production or “kills” the well. Often, the continuous removal of fluids results in daily gas production rates that are higher than the production rates prior to the plunger lift installation.

Reduced paraffin and scale buildup. In wells where paraffin or scale buildup is a problem, the mechanical action of the plunger running up and down the tubing may prevent particulate buildup inside the tubing. Thus, the need for chemical or swabbing treatments may be reduced or eliminated. Many different types of plungers are manufactured with “wobble-washers” to improve their “scraping” performance.

Other economic benefits. In calculating the economic benefits of plunger lifts, the savings from avoided emissions and enhanced production are only two factors to consider in the analysis. Additional savings may result from lower operational and well work costs.

Tradeoffs

Plunger lift systems do fail and can require additional maintenance versus blowing wells down. If return velocity is not controlled they may also “launch” through the plunger receiver and cause wellhead failure. Also, dependent on the control systems, they may require regular operator intervention.

Burdens

Installation of plunger lift systems can involve substantial costs particularly if changes to the well-bore tubulars are required. If adequate control systems and a means to power them are not available on a particular well, their installation will require additional expenditures.

II. Description of how to implement

A. Mandatory or voluntary: This option should be voluntary given the restrictions on applicability posed by well-bore configuration, pressure and build-up profile, and production characteristics. Each well must be evaluated for feasibility of plunger lift systems. A large number of wells in the Four Corners area already have artificial lift systems or other enhanced deliquification techniques already installed.

Requiring all wells in the basin to replace other means of enhanced or artificial lift would be logistically and operationally unreasonable. A large percentage of the producing wells in the 4-corners area are already equipped with plunger lift systems. Most operators have an ongoing well evaluation program to determine the appropriate deliquification technology to apply to any particular well.

B. Indicate the most appropriate agency(ies) to implement: Non-applicable – voluntary implementation. However, workshops on plunger lift applicability, control, and operation may enhance implementation.

III. Feasibility of the option

A. Technical: The technical considerations necessary for plunger lift systems are well known and plunger lift systems are feasible where the well characteristics enable application. For very low pressure/flow environments, such as portions of the San Juan Basin, operation of plunger lifts may require periodic venting (blow-down) of well-bores to the atmosphere to generate enough differential energy to lift the plunger and associated fluids. Advanced control systems can significantly reduce the need for this type of blow-down but require robust automation capabilities.

B. Environmental: There are no known environmental issues with plunger lift implementation and they typically reduce emissions.

C. Economic: the economics of applying plunger lift technology to a particular well must be evaluated on a well-by-well basis. For wells where they are applicable, plunger lift systems are generally economic.

IV. Background data and assumptions used N/A

V. Any uncertainty associated with the option

Assuming a well-by-well evaluation of applicability the uncertainty associated with plunger lift implementation should be low. Due to the large number of wells already equipped with plunger lift or other enhanced or artificial lift systems the scope of available implementation may be limited.

VI. Level of agreement within the work group for this mitigation option

Still being evaluated, but based upon information to date it should be high.

Mitigation Option: Implementation of Reduced Emission Completions (Green Completions)

I. Description of the mitigation option

The “green completions” control method reduces methane losses during gas well completions. During well completions it is necessary to clean out the well bore and the surrounding formation perforations. This is done both after new well completions and after well workovers. Operators produce the well to an open pit or tanks to collect sand, cuttings and reservoir fluids for disposal. Normal practice during this process is to vent or flare the natural gas produced. Venting may lead to dangerous gas buildup, so flaring is preferred where there is no fire hazard or nuisance issue (concerns about smoke, light, noise, etc.). Green completions recover the natural gas and condensate produced during well completions or workovers. This is accomplished using portable equipment to process the gas and condensate so it is suitable for sale. The additional equipment may include more tanks, special gas-liquid-sand separator traps, and portable gas dehydration. The recovered gas is directed through permanent dehydrators and meters to sales lines, reducing venting and flaring. “Green completion” techniques are only applicable where the reservoir pressure and flow is sufficient to clean-up a well bore after completion and still have sufficient pressure to enter the collection system/pipeline. With the depleted status of the conventional San Juan basin reservoirs and the characteristics of coal bed methane reservoirs; this is not an available option for the SJ basin area.

II. Description of how to implement

A. Mandatory or voluntary

This process can be mandatory or voluntary.

B. Indicate the most appropriate agency(ies) to implement

For the 4 Corners area, State regulatory agencies could require green completions through regulation or policy. For example, in the Pinedale, WY area the State of Wyoming, BLM, and operators have agreed to minimize flaring operations through use of green completions. FLMs could require this process through stipulations or conditions of approval in leases and applications for permits to drill.

III. Feasibility of the option

A. Technical

The green completion process can apply to the drilling of all natural gas wells, however, a sales line connection and sales agreements need to be arranged before the well drilling is completed. There are operational, access and other considerations that make this a case determination.

Differing opinion: This technique is not feasible in the SJ basin – see above.

The green completion process has been reviewed by EPA and is listed under “Recommended Technologies and Practices” on EPA’s Natural Gas Star Program web site:

<http://www.epa.gov/gasstar/techprac.htm> **Differing opinion:** This technology may not be applicable in all cases, and needs careful consideration. Different formations typically require different completion techniques that this technology may not be suited to handle. E.g. many operators use compressed air to fracture coal wells. Air mixed with natural gas cannot be shipped to a pipeline due to the high potential for spontaneous combustion under typical pipeline temperatures and pressures. Additionally, oxygen contamination of natural gas causes additional corrosion risks to gathering lines. Separation of air from natural gas is presently not feasible or part of the process equipment used in “green completions.”

B. Environmental

Nationally EPA has estimated that 25.2 billion cubic foot (Bcf) of natural gas can be recovered annually using Green Completions - 25,000 million cubic foot (MMcf) from high pressure wells, 181 MMcf from low pressure wells, and 27 MMcf from workovers. This reduces emissions of methane (a greenhouse gas), condensates (hazardous air pollutants), and nitrogen oxides (precursor to ozone formation and

visibility degradation) formed when gas is flared. An EPA Gas Star Partner reported an estimated methane emissions reduction, as the total recovered from 63 wells, of 7.4 MMcf per year, which is 70 percent of the gas formerly vented to the atmosphere.

C. Economic

A methane savings of 7 MMcf per year based on completing 60 wells per year at the average recovery reported by an EPA Gas Star partner. The partner also reported recovering a total of 156 barrels of condensate from the 63 wells, an average of 2.5 barrels per well.

The capital costs include additional portable separators, sand traps, and tanks at a cost reported by the partner of \$180,000. This equipment would be moved from well-to-well, so amortizing the cost over 10 years and doing 60 wells per year, the annual capital charges would be under \$10,000. Incremental operating costs are assumed to be over \$1,000 per year. At a natural gas price of \$3 per Mcf and condensate price of \$19 per barrel, green completions will pay back the costs in about 1 year. This information is for green completions in the Green River Basin area of Wyoming and is for much higher rate wells with much higher pressures and energy than the SJ basin wells.

IV. Background data and assumptions used

Information on Green Completions comes from EPA's Natural Gas Star Program web site:

<http://www.epa.gov/gasstar/techprac.htm>

V. Any uncertainty associated with the option

Low, if the well is part of an in-fill and a sales line connection is available. Other situations may not be suitable for green completions.

Differing opinion: Very High – this is not a viable option for the SJ basin area – see above.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None.

Mitigation Option: Convert High-Bleed to Low or No Bleed Gas Pneumatic Controls

I. Description of the mitigation option

This option would encourage oil and gas producers and pipeline owners and operators to replace or retrofit high-bleed natural gas pneumatic controls. This option should be considered when replacement of pneumatic controls with compressed instrument air systems is not practical or feasible (e.g. no electric power supply). It would enhance EPA's current efforts in the Natural Gas Star Program and make them specific to the San Juan Basin. This would result in a significant reduction in methane emissions as well as achieve cost savings for the companies.

Pneumatic instrument systems powered by high-pressure natural gas are often used across the natural gas and petroleum industries for process control. Typical process control applications include pressure, temperature, liquid level, and flow rate regulation. As part of normal operation, natural gas powered pneumatic devices release or bleeds gas to the atmosphere and, consequently, are a leading source of methane emissions from the natural gas industry. High-bleed pneumatic devices are defined as those with bleed rates of 6 standard cubic feet per hour (scfh) or 50 thousand cubic feet (Mcf) per year. An EPA study in 2003 reported the constant bleed of natural gas from these controllers was collectively one of the largest sources of methane emissions in the natural gas industry, estimated at approximately 24 billion cubic feet (Bcf) per year in the production sector, 16 Bcf from processing and 14 Bcf per year in the transmission sector. Pneumatic control systems emit methane from tube joints, controls, and any number of points within the distribution tubing network.

Companies have found that the payback period can be less than a year for most retrofits from high-bleed to low-bleed pneumatic controllers. Recent experience indicates that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted. If electric power is available, conversion from natural gas-powered pneumatic control systems to compressed instrument air systems will result in greater methane emissions reductions. However, the investment payback period will likely be longer, and may not be cost effective in some cases.

In compressed instrument air systems, atmospheric air is compressed, stored in a volume tank, filtered and dried for instrument use. All other parts of a gas pneumatic system work the same way with air as they do with gas. Existing pneumatic gas supply piping, control instruments, and valve actuators of the gas pneumatic system can be reused in an instrument air system. Reducing methane emissions from pneumatic devices by converting to instrument air systems can yield significant economic and environmental benefits for natural gas companies including:

- Financial Return From Reducing Gas Emission Losses. In many cases, the cost of converting high-bleed to low-bleed pneumatic controllers can be recovered in less than a year.
- Lower Methane Emissions

II. Description of how to implement

A. Mandatory or voluntary: This program would be voluntary. Due to the fact that almost all high-bleed pneumatics have been replaced by the industry, the economic returns from implementing low bleed systems should motivate producers to implement them. State and Federal agencies can assist by advertising the benefits, as is currently done by EPA's Natural Gas Star Program.

B. Currently most operators have already replaced all high bleed with low bleed systems.

C. Indicate the most appropriate agency(ies) to implement: EPA and the State environmental agencies would extend and enhance EPA's current efforts to make them specific to the San Juan Basin.

III. Feasibility of the option

A. Technical: These systems are off-the-shelf and proven.

B. Environmental: The environmental benefits of replacing high-bleed with low-bleed pneumatic controls, in terms of lower methane emissions, have been documented by EPA. Companies reporting to EPA have reduced emissions by 50-260 Mcf per year per controller.

C. Economic: EPA reports that replacing or retrofitting high-bleed units with low-bleed units have a payback of five to 21 months.

IV. Background data and assumptions used

See the website for EPA's Natural Gas Star Program: <http://www.epa.gov/gasstar/index.htm>

In particular, the lessons learned summaries for low-bleed pneumatics:

http://www.epa.gov/gasstar/pdf/lessons/ll_pneumatics.pdf

V. Any uncertainty associated with the option

Low. This is proven technology with proven benefits.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups

Cumulative effects should review oil and gas tasks and rank those most effective as priorities over those less effective or cost effective.

Mitigation Option: Utilizing Electric Chemical Pumps

I. Description of the mitigation option

This option involves replacing existing gas drive pumps with solar powered, electric-driven chemical pumps. The air quality benefits would be to minimize methane and VOC emissions to the atmosphere (Methane, VOC).

Economic burdens are significant but not insurmountable if the cost recovery factor from reduced fuel usage over the anticipated life of the unit shows a positive return on investment.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.

Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to install electric-driven, solar powered chemical pumps are envisioned as “voluntary” measures since the feasibility of installing insulation on new units or retrofitting existing units must be evaluated for a positive Net Present Value (NPV) or Return on Investment (ROI) in the Four Corners area. If the NPV or ROI meets a company’s investment targets, then utilization of this technology should be encouraged as a best practice. There are no existing mandates by the respective Air Quality Control agencies to require electric drive pumps as BACT. Since the Four Corners area is not in ozone non-attainment and the cost economics will not always justify installation of insulation for economic benefit, a voluntary approach is recommended.

B. Indicate the most appropriate agency(ies) to implement: The states.

III. Feasibility of the option

A. Technical: The purchase and installation of electrically driven chemical pumps is technically feasible. Currently some companies are installing these pumps on a trial basis to assure performance during the winter months.

B. Environmental: The environmental benefits of reduced Methane and VOC pollution are well documented.

C. Economic: The use of electric-driven, solar powered chemical pumps is economically feasible where there is payback that meets the respective companies targets for investments (i.e., ROI or NPV). For existing older pumps exist on wells that have a future limited life, the economics may not justify the application of insulation.

IV. Background data and assumptions used

Most chemical pumps in the Four Corners area are utilized year round to achieve their objective.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option

There is general agreement among working group members that the use of electrical chemical pump technology in the Four Corners areas is economically unfeasible and a likely source for voluntary adoption if the economics show a sufficient NPV.

Mitigation Option: Solar Power Driven Wellsites and Tank Batteries

I. Description of the mitigation option

This option comprises a system of production equipment and controls powered by solar generated electricity (through Photovoltaic – PV - cells) at gas well production sites that are not served with grid power. In most cases solar power replaces pressurized fuel gas, which is usually vented to the atmosphere after use. The power supply consists of solar panels and batteries. The solar power is used for electric instruments, controllers, actuators for automatic valves and small additive (methanol) pumps. Optimization consists of selecting the best fit items of hardware, becoming familiar with the strengths and limitations of all of the individual items as well as the overall system and making modifications to improve performance.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory on all new wellsites with gas-assisted chemical injection pumps. Mandatory where economic at existing wellsites. Propose to define a standardized calculation to determine if it is economic. An example borrowed from the Alberta EUB – Energy & Utilities Board – Directive 60, agreed to by a multi-stakeholder group including the oil & gas industry, includes the following:

- 1) Before tax basis
- 2) Point to an agreed upon specific gas forecast report
- 3) Must have remaining reserves calculation and production forecast (NPV calculated over life of well/production)
- 4) Only incremental capital costs related to the solar PV skid system may be included
- 5) Long term inflation based on CPI forecast
- 6) Discount rate = prime lending rate + 3%
- 7) Only revenue minus net royalties from incremental gas conservation only to be included
- 8) Economic if NPV before tax > \$0

B. Indicate the most appropriate agency(ies) to implement: The States on State land or Federal/Tribe on Indian country.

III. Feasibility of the option

A. Technical: In the past two years an operator in Alberta has installed over 40 of these systems. Supported by operations managers, instrumentation personnel carried out trials with solar systems and electrical equipment to arrive at a “best fit” arrangement. In summer 2006, this operator carried out a study with outside specialist consultants in energy consumption and emissions monitoring to evaluate the performance of the system. The results of the study were very positive, resulting in this operator making their solar PV system the company standard for gas well production. The primary reasons for this are to reduce fuel consumption in producing operations, increase sales gas revenues and reduce vent gas emissions. There are also operators in the US Rocky Mountain area using solar PV systems in comparable ways.

B. Environmental: Reduced VOC emissions and reduced methane emissions (with a global warming potential ~23 times greater than CO₂). Quantity of reduction would be dependent on number and bleed rate of pneumatic controllers, and size and supply gas use rate of pneumatic pump equipment, being replaced with electrically-powered devices.

C. Economic: Reduced fuel gas consumption so increased gas conservation and saleable product. These solar PV systems also minimize the requirement for expensive fuel gas regulators, shutdown devices and repair kits and stainless steel instrument tubing and fittings.

IV. Background data and assumptions used

See the presentation, “BP Canada Energy Company Innovative Methods for Reducing Greenhouse Gas - Low Emissions Wellsite” by Milos Krnjaja, BP Canada made at the “Energy Management Workshop for Upstream and Midstream Operations: Increasing Revenue through Process Optimization & Methane Emissions Reduction” in Calgary, Alberta Canada on 15-17 January 2007.

(http://www.methanetomarkets.org/events/2006/oil-gas/docs/15jan07-bp_canada_energy_company.pdf)

See the presentation, “Using Solar to Reduce Fugitive Gas Emissions” by Stuart Torr, Komex International made at the 2005 Energy Conservation and Air Emissions Technology Forum Wednesday, in Calgary, Alberta Canada on 19 October 2005.

(<http://www.ptac.org/eet/dl/eetf0501p12.pdf>)

See Database of State Incentives for Renewables and Efficiency (DSIRE) for a fast and convenient method to access comprehensive information on available state, local, utility, and federal **financial incentives** that promote renewable energy and energy efficiency.

(<http://www.dsireusa.org/>)

See Alberta Energy & Utilities Board – Directive 60 – Upstream Petroleum Industry Flaring, Incinerating, and Venting.

(<http://www.eub.ca/docs/documents/directives/Directive060.pdf>)

See Ber-Mac Electrical and Instrumentation for an example of a supplier of solar PV systems for instrumentation use. They have been in business since 1980 supplying electrical power and instrumentation equipment and services, both domestically and to international markets, supplying the needs of oil and gas companies all over the world. Their “Green Machine” is an environmentally-friendly, solar-powered operating system for new and existing wellsites.

(<http://www.ber-mac.com/greenmachine.htm>)

V. Any uncertainty associated with the option Low – a fair amount of industry experience and vendor capacity to-date.

VI. Level of agreement within the work group for this mitigation option

General agreement within working group members that this is viable.

EXPLORATION & PRODUCTION: PNEUMATICS / CONTROLLERS / FUGITIVES

Mitigation Option: Optical Imaging to Detect Gas Leaks

I. Description of the mitigation option

This option would encourage oil and gas producers and pipelines to use optical imaging to detect methane and other gaseous leaks from equipment, processing plants, and pipelines.

Optical imaging refers to a class of technologies that use principles of infrared light and optics to create an image of chemical emission plumes. They offer more cost-effective use of resources than traditional hand-held emissions analyzers, can screen hundreds of components or miles of pipeline relatively quickly and allow quicker identification and repair of leaks. The remote sensing and instantaneous detection capabilities of optical imaging technologies allow an operator to scan areas containing tens to hundreds of potential leaks, thus eliminating the need to visit and manually measure all potential leak sites.

Gas imaging can be either active or passive. Active gas imaging is accomplished by illuminating a viewing area with laser light tuned to a wavelength that is absorbed by the target gas to be detected. As the viewing area is illuminated, a camera sensitive to light at the laser wavelength images it. If a plume of the target gas is present in the imaged scene, it absorbs the laser illumination and the gas appears in a video picture as a dark cloud. Because it relies on the detection of backscattered radiation from surfaces in the scene, the process is referred to as Backscatter Absorption Gas Imaging (BAGI).

Passive gas imaging is based on a complex relationship between emission, absorption, reflection, and scatter of electromagnetic radiation. VOCs in the vapor phase have unique spectral emission and absorption properties. By measuring these properties, the gas species can be uniquely identified. By tuning the instrument's spectral response to the unique spectral region of the VOC, the camera can make an image of a gas plume.

There is a variety of technologies available and in different stages of development for imaging hydrocarbon gases. Plume imaging technologies include BAGI and Hyperspectral Imaging systems. Remote detection sensing instruments include Open-path Fourier Transform Infrared (OP-FTIR), Differential Absorption Spectroscopy (DOAS), Light Detection and Ranging (LIDAR-DIAL), and Tunable Diode Laser Absorption Spectroscopy (TDLAS). These instruments can be hand held or shoulder mounted, van mounted, or operated from a helicopter or fixed wing aircraft, depending on the technology and the facility to be inspected.

As an example, the ANGEL service, which uses Differential Absorption Lidar (DIAL), can detect specific hydrocarbon gases with color video imaging from a fixed wing aircraft, quantify the plume concentration, encode GPS data on the image, and cover 1000 miles per day. This technology is most suited to a facility such as a pipeline or tank farm. For a gas processing plant, a hand held or shoulder mounted camera may be the technology of choice.

The benefits of using optical leak detection in an inspection and maintenance program include:

- Reductions in hydrocarbon gas emissions, both greenhouse gases and hazardous air pollutants;
- Improved safety; and
- Typical payback of less than one year in reduced methane product losses.

II. Description of how to implement

A. Mandatory or voluntary: This program would be a voluntary Best Management Practice. The economic returns from implementing optical leak detection should motivate producers to implement

them. State and Federal agencies can assist by advertising the benefits, as is currently done by EPA's Natural Gas Star Program.

B. Indicate the most appropriate agency(ies) to implement: EPA and the state environmental agencies would extend and enhance EPA's current efforts to make them specific to the San Juan Basin.

III. Feasibility of the option

A. Technical: Several of these systems are commercially available.

B. Environmental: The environmental benefits of using optical imaging to detect and repair leaks have been documented. Companies reporting to EPA have reduced emissions significantly. Individual company results can be found on the EPA Natural Gas Star Program web site referenced below.

C. Economic: EPA reports that optical leak detection surveys pay for themselves in less than a year.

Differing opinion: Must be evaluated for each operation, may not be economic or applicable for all.

IV. Background data and assumptions used

See the web site for EPA's Natural Gas Star Program: <http://www.epa.gov/gasstar/index.htm>

Individual companies' experience with optical imaging leak detection:

Dynergy: http://www.epa.gov/gasstar/pdf/ngstar_fall2005.pdf

Enbridge: <http://www.epa.gov/gasstar/workshops/houston-oct2005/dodson.pdf>

Also see the agendas from the 2003 – 2005 Gas STAR Program annual implementation workshops: http://www.epa.gov/gasstar/workshops/imp_workshops.htm

Information on the ANGEL-DIAL technology:

http://www.epa.gov/gasstar/workshops/kenai/itt_sstearns.pdf

http://www.epa.gov/gasstar/pdf/ngspartnerup_spring06.pdf

Texas Commission on Environmental Quality report that includes comparison of various imaging technologies: http://www.tceq.state.tx.us/implementation/air/terp/Prop_02R04.html

V. Any uncertainty associated with the option Low. This is proven technology with proven benefits.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None known.

Mitigation Option: Convert Gas Pneumatic Controls to Instrument Air

I. Description of the mitigation option

This option would encourage oil and gas producers and pipelines to convert pneumatic controls from natural gas to compressed instrument air systems. It would enhance EPA's current efforts in the Natural Gas Star Program and make them specific to the San Juan Basin. This would result in a significant reduction in methane emissions as well as achieve cost savings for the companies.

Pneumatic instrument systems powered by high-pressure natural gas are often used across the natural gas and petroleum industries for process control. Typical process control applications include pressure, temperature, liquid level, and flow rate regulation. As part of normal operation, natural gas powered pneumatic devices release or bleed gas to the atmosphere and, consequently, are a major source of methane emissions from the natural gas industry. The constant bleed of natural gas from these controllers is collectively one of the largest sources of methane emissions in the natural gas industry, estimated at approximately 24 billion cubic feet (Bcf) per year in the production sector, 16 Bcf from processing and 14 Bcf per year in the transmission sector. Pneumatic control systems emit methane from tube joints, controls, and any number of points within the distribution tubing network.

Companies can achieve significant cost savings and methane emission reductions by converting natural gas-powered pneumatic control systems to compressed instrument air systems. Instrument air systems substitute compressed air for the pressurized natural gas, eliminating methane emissions and providing additional safety benefits. Cost effective applications, however, are limited to those field sites with available electrical power.

In compressed instrument air systems, atmospheric air is compressed, stored in a volume tank, filtered and dried for instrument use. All other parts of a gas pneumatic system work the same way with air as they do with gas. Existing pneumatic gas supply piping, control instruments, and valve actuators of the gas pneumatic system can be reused in an instrument air system.

Reducing methane emissions from pneumatic devices by converting to instrument air systems can yield significant economic and environmental benefits for natural gas companies including:

- Financial Return from Reducing Gas Emission Losses. In many cases, the cost of converting to instrument air can be recovered in less than a year.
- Increased Life of Control Devices and Improved Operational Efficiency
- Avoided Use of Flammable Natural Gas. By eliminating the use of a flammable substance, operational safety is significantly increased.
- Lower Methane Emissions
-

The conversion of natural gas pneumatics to instrument air system is applicable to all natural gas facilities and plants where an electric power supply is available. For those sites that do not have electricity available, cost savings and methane emissions reductions can still be achieved by replacing high-bleed pneumatic devices with low bleed devices, retrofitting high-bleed devices, and improving maintenance practices. Experience has shown that these options often pay for themselves in less than a year.

II. Description of how to implement

A. Mandatory or voluntary: This program would be voluntary. The economic returns from implementing instrument air or low bleed systems should motivate producers to implement them. State and Federal agencies can assist by advertising the benefits, as is currently done by EPA's Natural Gas Star Program.

B. Indicate the most appropriate agency(ies) to implement: EPA and the state environmental agencies would extend and enhance EPA's current efforts to make them specific to the San Juan Basin.

III. Feasibility of the option

A. Technical: These systems are off-the-shelf and proven. Best utilized at larger facilities.

B. Environmental: The environmental benefits of replacing high-bleed pneumatic controls with instrument air, in terms of lower methane emissions, have been documented by EPA. Companies reporting to EPA have reduced emissions by an average of 20 Bcf per year per facility.

C. Economic: EPA reports that instrument air systems pay for themselves in less than a year. Replacing or retrofitting high-bleed units with low-bleed units have a payback of five months to one year.

Differing opinion: May not be economically justifiable or operationally sound for small facilities and well sites.

IV. Background data and assumptions used

See the web site for EPA's Natural Gas Star Program: <http://www.epa.gov/gasstar/index.htm>

In particular, the lessons learned summaries for instrument air:

http://www.epa.gov/gasstar/pdf/lessons/II_instrument_air.pdf

And for low-bleed pneumatics:

http://www.epa.gov/gasstar/pdf/lessons/II_pneumatics.pdf

V. Any uncertainty associated with the option Low: this is proven technology with proven benefits.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None known.

EXPLORATION & PRODUCTION: MIDSTREAM OPERATIONS

Mitigation Option: Application of NSPS and MACT Requirements for Existing Sources at Midstream Facilities

I. Description of the mitigation option

Overview

- This mitigation option would involve filling in the gaps where the NSPS and MACT fail to adequately regulate sources at midstream facilities. Filling in the gaps could include lifting exemptions on existing sources and lowering applicability thresholds. Specific examples include:
 - Subjecting existing stationary combustion turbines at midstream facilities to 40 CFR Part 63, Subpart YYYY;
 - Requiring existing 2 stroke lean burn and 4 stroke lean burn reciprocating internal combustion engines to meet 40 CFR Part 63, Subpart ZZZZ MACT standards at midstream facilities;
 - Requiring boilers, reboilers, or heaters with a design capacity of less than 10 mmBtu/hr to meet NSPS at 40 CFR Part 60, Subpart Dc at midstream facilities;
 - Requiring all midstream facilities to meet the requirements to 40 CFR Part 60, Subpart KKK; and
 - Requiring all amine sweetening units at midstream facilities to meet 40 CFR Part 60, Subpart LLL requirements.

This option would involve case-by-case assessments of midstream facilities to determine whether additional pieces of equipment should be regulated under NSPS and MACT standards and to assess the feasibility of such regulation. The overall goal is to use NSPS and MACT standards as guides for further air pollution reductions at midstream facilities.

Air Quality/Environmental

- This mitigation option would lead to further reductions in hazardous air pollutants and criteria air pollutants by subjecting more units to regulation. By requiring more facilities and/or units to comply with NSPS and MACT, there may be an incentive to upgrade to cleaner equipment, which would provide additional air quality benefits.

Economics

- There would likely be additional costs associated with bringing previously unregulated facilities and/or units into compliance.
- The option may provide an incentive to replace older, less efficient equipment, which could lead to increased efficiency.
- There would be potential paybacks associated with methane recovery by complying with NSPS at Subpart KKK.

Tradeoffs

- None.

Burdens

- The burden would be on industry to bring facilities and/or units into compliance with the NSPS and MACT standard. Air quality impacts would be reduced, reducing burden on health and welfare. Regulatory agencies may have to revise rules to implement this mitigation options.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory. NSPS and MACT standards work best as mandatory requirements.

B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies, EPA.

III. Feasibility of the option

A. Technical: There will need to be case-by-case assessments, but this appears to be a technically feasible option.

B. Environmental: No environmental feasibility issues are known.

C. Economic: There may be economic concerns that should be addressed, but this option is not infeasible based on economics. The goal is clean air and that may take an investment.

D. Other: There will likely need to be rule changes to implement this option that may present feasibility issues.

IV. Background data and assumptions used

Background data and assumptions used came from review of EPA NSPS and MACT standards.

V. Any uncertainty associated with the option (Low, Medium, High):

Low uncertainty. The NSPS and MACT provide a solid basis for air pollution control options. However, further discussion and comments may reveal other means of using NSPS and MACT standards to keep air pollution in check.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups: None.

Mitigation Option: Specific Direction for How to Meet NSPS and MACT Standards: Directed Inspection and Maintenance

I. Description of the mitigation option

Overview

Meeting NSPS and MACT standards at Midstream facilities can often be achieved using a variety of methods, some of which may be better than others. For example, the EPA is proposing to allow the use of infrared cameras to meet Leak Detection and Repair (LDAR) requirements set forth in several NSPS and MACT standards. 70 Fed. Reg. pp. 17401-17409. The EPA has indicated that infrared cameras can provide better data than Reference Method 21.

This mitigation option provides specific direction on how to meet NSPS and MACT standards so that the best methods of compliance are met. Specifically, it requires operators to use approved infrared cameras to meet LDAR requirements set forth at 40 CFR Part 60, Subpart KKK and 40 CFR Part 63, Subpart HH and HHH.

It would also require operators to implement cost-effective options for reducing methane emissions, as outlined in Fernandez, et al. 2005, to meet applicable NSPS and MACT standards. These cost-effective options would vary depending on the equipment, but would include using vapor recovery units on tanks and dehydrators, using desiccant dehydrators rather than glycol dehydrators, replacing compressor rod packing after three years, replacing gas starters on compressor engines with air starters, and converting gas pneumatics at facilities to instrument air.

Air Quality/Environmental

- Meeting LDAR requirements using infrared cameras promises to better keep volatile organic compound and hazardous air pollutant emissions from leaking equipment in check. Implementing cost-effective options for reducing methane emissions will further reduce emissions. In both cases, methane emissions would be reduced, preventing further greenhouse gas emissions.

Economics

- This mitigation option will most likely yield a payback due to the recovery of methane. According to one case study, BP recovered \$2.4 million in 2 months simply by recovering over 123 MMcf/yr of that was lost due to equipment leaks (see, <http://www.epa.gov/gasstar/workshops/hobbs72706/dim.pdf>).

Tradeoffs

- The use of some cost-effective methane control options may require the use of electricity, such as vapor recovery units, which may be generated through coal or natural gas burning. Potential increases in emissions from electricity generation could be prevented through the use of solar or other renewable energy sources.

Burdens

- The only burden would be the restriction of flexibility for the operators and the investment cost.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory. Although infrared cameras and methane control options can provide paybacks and are proven cost-effective, they are not widely used. Despite potential paybacks, current incentives do not appear to be strong enough to encourage their use. Mandatory requirements would provide that incentive.

B. Indicate the most appropriate agency(ies) to implement: State air quality agencies and EPA.

III. Feasibility of the option

- A. Technical: Feasible, these technologies are already in use and are being implemented elsewhere.
- B. Environmental: Vapor recovery units may require additional space at midstream facilities and could pose additional environmental impacts. This seems to present a limited environmental feasibility issue.
- C. Economic: Given the paybacks from methane recovery, there are no economic feasibility issues.
- D. Other: The EPA has not yet finalized its proposal to allow infrared cameras to be used solely to meet LDAR requirements in the NSPS and MACT.

IV. Background data and assumptions used

Background data was obtained from information on the EPA's Natural Gas Star Program website, www.epa.gov/gasstar, from the EPA's proposal to allow infrared cameras to be used to meet LDAR requirements at 70 Fed. Reg. 17401-17409, and from the Fernandez et al. 2005 paper, "Cost Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers," available online at <http://www.epa.gov/outreach/gasstar/pdf/CaseStudy.pdf>.

V. Any uncertainty associated with the option

Low uncertainty, especially with regards to the use of infrared cameras as effective tools to comply with NSPS and MACT LDAR requirements. Operators would still have to show that cost-effective methane control options would meet the applicable requirements of the NSPS and MACT.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups

Possibly the Cumulative Effects Group due to indirect emission increases from coal or natural gas burning plants that may accompany increased use of vapor recovery units or other methane control options requiring electricity.

OIL & GAS OVERARCHING

Mitigation Option: Lease and Permit Incentives for Improving Air Quality on Public Lands

I. Description of the mitigation option

This option would provide incentives in the form of exceptions or waivers from lease stipulations or permit conditions of approvals (COAs) for oil and gas drilling on public lands in exchange for a program of environmental mitigation activities that would reduce air emissions along with other types of environmental and ecological impacts.

Differing Opinion: The proposed activities that would reduce air emissions and surface disturbance in this section should become standard practices **but without** the proposed exchange for the exceptions or waivers from seasonal wildlife restrictions which would negatively impact public lands wildlife.

This option could provide incentives in the form of expedited permit processing for operating permits in exchange for a program of environmental mitigation activities that would require documented reductions in emissions from major and minor sources. This option is not intended to reduce protection for wildlife. Monitoring and adjustments in response to monitoring results would be used to assure that the package of mitigation activities and associated development does not adversely affect wildlife.

Differing Opinion: Additionally these incentives would not include the exception of waivers from lease stipulations or permit conditions of approval (“COAs”) for oil and gas drilling on public lands.

Expedited operating permit issuance from the appropriate agency in exchange for additional emissions reductions offers incentives for both industry and the agencies

Industry Incentives include:

- The streamlining of operating permits.
- Direct and prompt cooperation with permit issuing agency.
- Obtaining an operating permit at an accelerated rate allows for an accelerated startup date, thus increased resource production (may be especially helpful for minor source operating permits).

Environmental Incentives include:

- The addition of emission control equipment such as a catalyst, Zero Emissions (a.k.a. Quantum Leap) Dehydrator, directional drilling, complying with emission limitations relating to hours of operation, lean burn engine, and/or implementing a program of environmental mitigation activities that would reduce air emissions.

This option would work well in the areas that smaller agencies, such as Tribes, oversee the operating permits. This option would be implemented by the applicable permitting agencies.

It would be modeled after the experience in the Pinedale Anticline and Jonah fields in Wyoming where producers face seasonal limitations on drilling due to concerns about wildlife impacts. As a result, drilling is prohibited for several months during the year, delaying development and increasing costs. Several producers have applied for and been granted permission to drill year round in exchange for efforts that mitigate environmental impacts. These efforts combine improved technologies and innovative practices that together greatly reduce adverse impacts. They include: directional drilling to reduce the number of drilling pads, and thus the amount of surface disturbance, by half or more; using natural gas-fired drilling rigs to reduce air emissions; transporting produced water by pipeline to eliminate truck trips;

using mat systems on drilling pads to reduce surface impact; partial remediation of drilling pads after the drilling phase; eliminating flares during well testing and completion to reduce air emissions and noise; centralized fracturing and production facilities; low impact road construction techniques; and produced water recycling. Producers and BLM will monitor wildlife impacts as part of the program. Year round drilling has the added benefits of reducing the duration of drilling operations by one third-to one-half, and increasing stability of the local community as workers move in with their families, rather than commuting seasonally.

Differing Opinion: This suggestion of modeling after the experience in Wyoming's Pinedale Anticline and Jonah fields fails to address the widespread and significant concerns that have been expressed regarding current and future impacts of oil and gas activity on wildlife in these fields and the wildlife population declines that have been documented through scientific studies. The Pinedale Anticline and Jonah field experience has not proven to be a model for wildlife, and recent proposals to increase drilling may even adversely impact a federally threatened species, the Bald Eagle, and further exacerbate problems for the sage grouse, a species which some believe should be listed as federally endangered because of recent population declines. Another report that helps put the Jonah field experience in perspective came in December 2006, stating that in places one well was being drilled per every five acres. Repeated concerns about the impact on wildlife in these areas of Wyoming have been expressed by numerous and diverse groups of people ranging from private citizens, outfitters, hunters, environmental organizations, scientists, to government agency personnel including personnel from Wyoming's Game and Fish Department. Drilling exceptions granted in crucial big game winter range around Pinedale early winter 2006/2007 were granted in the face of opposition by Wyoming's Game and Fish Department.

Differing Opinion Continued: Monitoring has also not been a model experience in this area. According to reports of a May 2006, internal assessment Pinedale, Wyoming, Bureau of Land Management field office, the office neglected its commitment to monitor and limit harm to wildlife and air quality from natural gas drilling in western Wyoming. A wildlife biologist who worked in that Pinedale office, Steve Belinda, is reported to have quit his job because he and other wildlife specialists were required to spend nearly all their time in the office processing drilling requests and were not able to go into the field to monitor the effect of the thousands of wells on wildlife.

This option would involve tradeoffs between seasonal restrictions, which would be relaxed, and a comprehensive wildlife and environmental impact plan which would use the kind of technologies and practices listed above. This plan would reduce impacts on wildlife, as well as on air quality, land and water resources, and on the local communities. Ecological and environmental monitoring would assess these impacts and allow for adjustments in the plans as activities proceed. All of these elements would be contained in agreements between the land management agencies and industry, with public input.

Differing Opinion: Exceptions or waivers from wildlife lease stipulations or permit conditions of approvals (COAs) for oil and gas drilling on public lands likely would increase negative impacts of oil and gas activities on wildlife in the Four Corners. At least in Northwest New Mexico and likely in the other Four Corners states, it is important to remember that the seasonal closures in the Bureau of Land Management Farmington Field Office management area exist only for parts of the year with their length dependent upon the animal species and the reason for the restriction such as elk calving or antelope fawning. The restrictions are in place to protect species during times of the year when they are especially vulnerable such as nesting for raptors; wintering for deer, elk, and Bald Eagles; and birthing and caring for young for antelope and elk. Provisions for waiving, excepting, or modifying the oil/gas lease stipulations already exist according to the Bureau of Land Management Farmington Field Office's 2003 Record of Decision for Farmington's Proposed RMP and Final Environmental Impact. These restrictions should remain in place to protect wildlife, especially with the current and anticipated intensity of drilling.

Differing Opinion Continued: An indication of the major potential for the impact of oil and gas activity on wildlife is found in the 2006 Annual Report of the Sublette Mule Deer Study conducted in the Pinedale Anticline Project Area. Study results that "suggest that mule deer abundance in the treatment area declined by 46 % in the first 4 years of gas development."

Differing Opinion Continued: In the summer, 2006, publication of the New Mexico Department of Game and Fish titled New Mexico Wildlife under the regional outlook for Northwest New Mexico, wildlife biologists are reported to be "concerned about the effects the severely dry spring had on fawn survival in the state's **already depressed deer herds.**" [Bolding is this author's.]

Differing Opinion Continued: Removal of the wintering restrictions for mule deer could create problems in New Mexico and in both this state and Colorado where migratory populations are shared. Another word of caution is found in the Upper San Basin Biological Assessment in the Comprehensive Wildlife Conservation Strategy (New Mexico's wildlife action plan accepted by the US Fish and Wildlife Service in 2006), which places mule deer in its list of Species of Greatest Conservation Need in the Colorado Plateau Ecoregion. Under "Problems Affecting Habitats or Species" in Chapter 5 of this document is this statement: "Of particular concern are energy development..." along with invasive species and livestock grazing practices. The document states that "coal bed methane development in the San Juan Basin is currently a major land use... Depending on the scale, density, and arrangement of each well site in relation to other sites, habitat loss and fragmentation in the portions of this habitat type [Big Sagebrush Shrubland] subjected to energy development are extensive. At this high level of development, effects may not be successfully mitigated."

Differing Opinion Continued: Pronghorn antelope numbers were so low at the time the Farmington Field Office's Draft Pronghorn Antelope Habitat Management Plan was published in March 2004, that the populations were described as struggling to survive, a change from when this species was common in the 1950's and 1960's. The restriction of drilling and construction activity during antelope fawning period from May 1 through July 15 was proposed as one of the ways to bring the populations back to eventual self-sufficiency.

These actions reduce air emissions from drilling rigs, from trucks (both diesel emissions and road dust), and from flaring. There are also benefits from reduced surface impacts and improved water management, as well as improved community stability.

Differing Opinion Continued: The actions that are offered that will reduce air pollution appear to be important ways to address our air quality problem and should become required practice because of the serious air pollution problems in the San Juan Basin. They should not come at an expense to area wildlife, which is already negatively impacted by direct and functional habitat loss due to oil and gas activities, as delineated in the 2003 Bureau of Land Management Farmington Field Office Draft Resource Management Plan and Environmental Impact Statement.

This option would work well in areas of the Four Corners region where new oil and gas projects are being proposed and where those projects face access limitations from wildlife stipulations or COAs. In these cases, the land management agencies (principally the BLM and the Forest Service) would have the greatest opportunity to negotiate agreements for infrastructure and operational changes from project start, in exchange for relaxing the access restrictions, along with monitoring for wildlife impacts. Monitoring of the air quality impacts, including documentation of reductions over similar projects without mitigation, would be required.

In New Mexico, this option could be integrated with the New Mexico Oil and Gas Association's (NMOGA) Good Neighbor Initiative.

Differing Opinion: Year round drilling will not improve air quality. The current drilling seasons are in place to protect the wildlife in the area. The improved technologies and innovative practices described above should be standard industry requirements and not be used in trade for expanded drill seasons.

Differing Opinion: BLM should not entertain compromising one environmental value in exchange for protecting another when industry is legally mandated to protect both. Year round drilling will only add to the stress wildlife currently experience in an already highly fragmented habitat. Even more, in the San Juan Basin industry has demonstrated their reluctance to routinely employ directional drilling as a means to avoid further habitat fragmentation. Since directional drilling “all wells” would be the cornerstone of the proposed mitigation option it seems that this options would not be favorably received by industry.

II. Description of how to implement

A. Mandatory or voluntary: This program would be voluntary and would rely on the operators, the agencies, and any local communities obtaining benefits from the arrangements.

B. Indicate the most appropriate agency(ies) to implement: BLM and the Forest Service on Federal land. State and tribal land management agencies may implement this option on state and tribal lands.

III. Feasibility of the option

A. Technical: The technological approaches to reducing impacts are already being implemented in Wyoming and other locations.

Differing Opinion: Four Corners states should use the technological approaches without industry cost being a factor.

B. Environmental: The environmental benefits of the mitigation measures are currently being documented in Wyoming. Many of them seem apparent. The impact of year round drilling (or other permit-related incentives) on wildlife would have to be closely monitored.

C. Economic: Many environmental mitigation measures turn out to be economically attractive as well (e.g., natural gas drilling rigs can reduce fuel costs by two-thirds). Year-round drilling can shorten the project length by one-third to one-half, improving project economics. Producers would have to anticipate an economic benefit in order to enter into agreements.

IV. Background data and assumptions used

Web sites and presentations from operators and BLM on the experience with this kind of agreement in Wyoming. The NMOGA web site has information on their Good Neighbor Initiative.

See the following web sites:

BLM environmental assessment of year-round drilling in the Pinedale Anticline Field:

<http://www.wy.blm.gov/nepa/pfodocs/questar/01ea.pdf>

(See especially section 2.5 on Applicant-Committed Mitigation.)

Questar presentation on development in Pinedale:

<http://www.wy.blm.gov/fluidminerals04/presentations/NFMC/028RonHogan.pdf>

BLM assessment of year round drilling demonstration project in the Pinedale Anticline Field:

<http://www.wy.blm.gov/nepa/pfodocs/asu/01ea.pdf>

Jonah Infill Project:

Encana release: http://www.encana.com/operations/upstream/us_jonah_blm.html

BLM air quality discussion:

<http://www.wy.blm.gov/nepa/pfodocs/jonah/92FEISAirQualSuppleQ-As.pdf>

BLM EIS and Record of Decision: <http://www.wy.blm.gov/nepa/pfodocs/jonah/>

NMOGA Good Neighbors Initiative:

<http://www.nmoga.org/nmoga/NMOGA%20Good%20Neighbor%20Initiative.pdf>

Wyoming Mule Deer Study Report (1 site)

http://www.west-inc.com/reports/big_game/PAPA_deer_report_2006.pdf

Wyoming wildlife, sage grouse

<http://stream.publicbroadcasting.net/production/mp3/wpr/local-wpr-563699.mp3>

<http://gf.state.wy.us/downloads/pdf/sagegrouse/Holloran2005PhD.pdf>

Wyoming wildlife, Bald Eagle <http://www.wy.blm.gov/nepa/pfodocs/anticline/seis/06chap3.pdf> 3-97

<http://www.wy.blm.gov/nepa/pfodocs/anticline/seis/07chap4.pdf> 4-123

Wyoming Bureau of Land Management, wildlife monitoring (1site)

<http://www.washingtonpost.com/wp-dyn/content/article/2006/08/31/AR2006083101482.html>

New Mexico: Comprehensive Wildlife Conservation Strategy (CWCS)

http://fws-nmcfwru.nmsu.edu/cwcs/New_Mexico_CWCS.htm

New Mexico—2003 Bureau of Land Management Resource Management Plan/Environmental Impact Statement, Record of Decision http://www.nm.blm.gov/ffo/ffo_p_rmp_feis/docs/Farmington_ROD.pdf
Appendix B

V. Any uncertainty associated with the option

Medium: Depends on opportunities (proposed projects) for implementing incentives in exchange for mitigation activities, on producer willingness to participate, and on BLM/FS state and regional office and tribal policy.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups Impacts from trucks and roads may overlap with the Other Sources work group.

Mitigation Option: Economic Incentives-Based Emission Trading System (EBETS)

I. Description of the mitigation option

The central idea of this option is that inherent economic incentives promote innovative ways to achieve emission reductions, including gains from efficiencies in operation and maintenance and in applications of new innovative engine and control technologies.

This option encourages the use of pollution markets through implementation of an emission trading system (ETS) along with cooperative partnerships to reduce air emissions with the aid of emission reduction incentives. Basically in an emission trading program, the governing authority (e.g., agency) issues a limited number of allocations in the form of certificates consistent with the desired or targeted level of emissions in an identified region or area. The sources of a particular air pollutant (e.g., NO_x) are allotted certificates to release a specified number of tons of the pollutant. The certificate owners may choose either to continue to release the pollutant at current levels and use the certificates or to reduce their emissions and sell the certificates. The fact that the certificates have value as an item to be sold or traded gives the owner an incentive to reduce the company's emissions. Simply stated in an ETS, a producer who has low-emission engines could sell emissions credits to a producer who has high-emission engines. Typically, 0.8 units of credit could be sold for each unit of reduction below the standard or reference level. The end result is a ratcheting down of overall emissions. This option does not contemplate multi-pollutant trading, but rather a separate market for each individual pollutant.

Approximately 30 state and federal ETS programs existed or were being developed in the U.S. in the later part of the 1990s. Examples of ETS that have worked reasonably well in achieving emission reductions and providing economic incentives to industry include the Illinois EPA's Emission Reduction Market System (ERMS), Indiana Department of Environmental Management's credit registry trading system, U.S. EPA's Acid Rain Program, and commercial and non-commercial institutions like Chicago Climate Exchange (CCX). In addition, in 2002 the US EPA approved a plan submitted by the WRAP, which contained recommendations for implementing the regional haze rule. The plan included an SO₂ emissions allowance trading program for nine Western states and eligible Indian tribes. As an example, EPA's program took about three years to plan and begin implementing.

The proposed economic incentives based emission trading system (EBETS) mitigation option can be developed or modeled after ETSS which have been successful and tailored to issues specific to the Four Corner region. Emission credits can accrue through a variety of methods that are complementary to or independent of other mitigation options developed herein by the Task Force. For example, credits can be gained through use of partnerships that provide incentives for voluntary emission reductions, such as in the EPA's Natural Gas STAR Program or New Mexico's VISTAS program (see the IBEMP mitigation option paper, OOP4). Credits for use or sale (e.g., sales within the ETS) can also be acquired through use of tax and/or lease incentives and through the initiatives coming from Small and Large Engine Subgroup (e.g., advanced ignition systems, use of electric engines, centralized large engine from many small engine mode of operations). In addition, opportunities exist for collaboration between engine manufacturers and producers for field testing new engine technology through a swap out program, dirty old for cleaner new. Finally, use of voluntary laboratory testing of a select group of existing engines (e.g. uncontrolled small, <300 hp, engines) could provide a means to identify innovative cost-effective modifications to improve engine efficiency and reduce engine emissions (SERP, 2006).

Benefits: Joint participation by oil and gas, electric power production, and other source category stakeholders provides opportunities for multi-pollutant emission reductions that cover key criteria air pollutants such as NO_x, SO₂, VOCs, PM_{2.5}, and PM₁₀. An added benefit could be realized by also including green house gases such as CO₂ and CH₄, in the mix. Examples of the emission reductions that

could be achieved by a well designed and implemented ETS are the 50% reduction from 1980 levels of SO₂ emissions from utilities under the ETS within US EPA's Acid Rain Program¹ and the 65% reduction from 1990 levels achieved under the Ozone Transport Commission NO_x Program (SERP, 2006).

Tradeoffs: The ETS could be designed to provide for pollutant emission allocation and/or credit tradeoffs (e.g., NO_x for SO₂ in NO_x limited regions) and trades between source groups or categories (e.g., oil and gas NO_x with power plant SO₂).

Burdens: The major burden would be administrative in nature. Who would be responsible for designing, setting up and administering the proposed EBETS program and how would it be funded?

II. Description of how to implement

- A. Mandatory or voluntary: Participation in the program would be voluntarily.
- B. Indicate the most appropriate agency (ies) to implement: The states.

III. Feasibility of the option

- A. Technical: The technical feasibility of ETS programs is well established and is in use around the world.

Differing opinion: Accurately and reliably measuring the emissions from oil and gas sources will prove challenging. EBETSs have had broad success because those that have been established rely heavily on good monitoring and reporting, and it is not clear that such techniques are available for the oil and gas sources of interest. Parametric, as opposed to direct exhaust emissions monitoring is one option, but the less direct/accurate/reliable the measurement, the more likely it is that some offset/discount will be demanded to make up for the uncertainty, e.g., if a source wanted to purchase credits as part of its compliance plan, it would have to purchase two instead of one. Alternatively, sources with relatively weaker emissions monitoring would be allowed to purchase credits, but not sell them. This latter approach was taken in the WRAP SO₂ Backstop Trading Program.

- B. Environmental: The feasibility in achieving significant emission reductions has been clearly demonstrated through use of well designed and implemented ETS programs. Inclusion and addition of "Best Management Practices," innovative technologies, improved maintenance and other pay-back incentives enhance the feasibility of achieving emission reductions required to meet air quality and visibility enhancement goals in the Four Corners Region.
- C. Economic: This program is economically feasible because emission trading provides economic incentives through implementation of complementary voluntary measures that reduce emissions, provide fuel savings, reduce operation and maintenance cost by adoption of BMPs and installation of innovative technologies. One recent study of projected economic gain by 2010 from the continued implementation of the ETS within the Acid Rain Program estimated it would provide an annual economic benefit of \$122 billion (in 2000 \$) at an annual cost of approximately \$3 billion (or a 1 to 40 cost-benefit ratio).

¹ The success of the Acid Rain Program ETS is evident from emissions data, which shows that SO₂ emissions were reduced by over 5 million tons from 1990 levels or about 34 percent of total emissions from the power sector. When compared to 1980 levels, SO₂ emissions from power plants have reduced by 7 million tons or more than 40 percent.

IV. Background data and assumption used

1. United States Environmental Protection Agency (USEPA) Acid Rain Program < <http://www.epa.gov/airmarkets/arp/index.html> >
2. Illinois Environmental Protection Agency Emission Reduction Market System (ERMS) <<http://www.epa.state.il.us/air/erms/>>
3. Argonne National Laboratory, Strategic Emission Reduction Plan, Draft, 2006.
4. Chicago Climate Exchange < <http://www.chicagoclimatex.com/> >

V. Any uncertainty associated with the option Medium to high.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups

A key crossover issue to establishing and implementing an effective EBETS is the facilitation of voluntary participation of electric utilities and other major source groups. This will provide the anticipated needed trade-offs in air pollutants (e.g., NO_x and SO₂) that participation by one or a limited number of source groups may not be able to provide.

Mitigation Option: Tax or Economic Development Incentives for Environmental Mitigation

I. Description of the mitigation option

This option provides for regulatory agencies and industry working together to utilize various legislative (state/federal/tribal) processes to achieve real emissions reductions. Emission reductions would be achieved by providing economic incentives that would encourage the industry to utilize lower emission internal combustion engines in various applications.

Emission reductions could be achieved through reducing the number of trucks in the field. This could be accomplished by providing incentives for companies to install underground piping in order to dispose of produced water. Criteria pollutants could be reduced by installing lower emissions compressor engines. Industry could be encouraged to install such engines by implementing tax incentives as described below.

Tax incentives provide economic relief to industry by reducing or eliminating taxes on certain equipment or activities. The equipment or activity must provide a recognized environmental benefit to the taxing entity that grants the incentive. Some examples of tax incentives currently being utilized are: (1) allowing costs of retrofitting existing engines or installing new engines to be fully deducted in the year they are incurred rather than being capitalized (2) tax credit certificates issued to program participants, which can be redeemed over a specified period of time (3) income tax credits upon installation of approved equipment.

The air quality benefits include net reduction of emissions, primarily of nitrogen oxides. However, reductions in sulfur oxides, greenhouse gas emissions and particulate matter emissions can also be calculated. Only positive environmental impacts have been identified. It is not anticipated that this strategy would cause any negative impacts, other than increased costs to industry. This strategy specifically provides for relief from such economic impacts.

Economic burdens include the cost to the oil and gas industry, engine manufacturers and other interest groups to develop and lobby legislative proposals. New technology would be more efficient, possibly resulting in increased production and reduced costs. The increased revenue would provide some offset to the initial costs of installation or retrofitting. Economic burden to the taxing entity would also occur. The taxpayers would, in effect, be subsidizing industry efforts to install or retrofit equipment to achieve lower emissions. Achieving taxpayer approval for such a subsidy might prove difficult.

Assistance from the Cumulative Effects Work Group could be helpful in estimating the potential cost-benefit of this option.

II. Description of how to implement

A. Mandatory or voluntary: Participation by industry or other groups would be voluntary, both in working to establish tax/economic development incentives and in taking advantage of such incentives.

B. Indicate the most appropriate agency(ies) to implement: States of Colorado and New Mexico. Counties of San Juan, NM; La Plata, CO; and other counties in the Four Corners area of impact. Indian tribes, including Jicarilla, Ute Mountain Ute, Southern Ute, Navajo, and others. These groups would need to work with state legislatures and/or Congressional representatives in getting sponsors to help draft an energy bill that includes tax incentives for improving Four Corners air quality.

III. Feasibility of the option

A. Technical: Many models of tax and economic development incentives are available. A list of some models follows, with more details contained in an Appendix to this document.

- i. Mineral Tax Incentives and the Wyoming Economy, May 2001, is an economic model. <http://legisweb.state.wy.us/2001/interim/app/reports/mineraltaxincentives.htm>
- ii. Brownfields Tax Incentive (1997 Taxpayer Relief Act P.L. 105-34). This model allows costs to be fully deductible in the year they are incurred, rather than having to be capitalized.
- iii. New York State Green Building Initiative. This tax credit program was developed by New York State Department of Environmental Conservation as per 6NYCRR Part 638. Tax credit certificates are issued and can be redeemed at any time over a designated period (i.e. 2006 – 2014).
- iv. Montana Incentives for Renewable Energy include property tax exemptions, industry tax credit, venture capital tax credits, and a low interest revolving loan program, special revenue local government bonds, and streamlined permitting processes for participants, income tax credits for retrofitting equipment.
- v. State of Virginia House Bill 2141, July 1997 allows the local governing body of any county, city, or town, by ordinance, to exempt, or partially exempt property from local taxation annually for a period not to exceed five years.
- vi. US EPA's Voluntary Diesel Retrofit Program is a non-regulatory, incentive-based, voluntary program designed to reduce emissions from existing diesel vehicles and equipment by encouraging equipment owners to install pollution reducing technology. This option would easily fit into the "partnership" mitigation option. However, it is also a model for the type of equipment that might qualify for a tax incentive.
- vii. Philippines Department of Natural Resources developed a single document that consolidates all tax incentives for air pollution control devices. Not new incentives, but a compilation of existing programs.
- viii. Western Regional Air Partnership diesel Retrofit program for diesel engines could be used as a model for other internal combustion engines. The guidance document for developing a retrofit program is found on the WRAP website. See Appendix for information. This option would easily fit into the "partnership" mitigation option. However, it operates similar to a tax incentive program and gives an example of how to set up a workable program.

B. Environmental: The environmental benefits of pollutant emissions reductions are well documented.

C. Economic: The entire concept of this mitigation option is that it must be economically viable.

IV. Background data and assumptions used

See Appendix for background studies.

Cooperation between the regulated community; local, state and tribal governments; and equipment manufacturers would have to be garnered in order for this option to work.

V. Any uncertainty associated with the option Medium

VI. Level of agreement within the work group for this mitigation option

The three member drafting team expressed no disagreement with this option.

VII. Cross-over issues to the other source groups

These tax incentive programs could also apply to other sources, such as power plants or vehicles.

APPENDIX

Mineral Tax Incentives and the Wyoming Economy, May 2001, is an economic model.

<http://legisweb.state.wy.us/2001/interim/app/reports/mineraltaxincentives.htm>

This model can be used to show the effects of all tax incentives previously granted, as well as the effects of hypothetical tax incentives or tax relief that might be considered in the future. Impacts include reduction in taxes; increased production; effects on federal, state and local government revenues.

Brownfields Tax Incentive fact sheets (EPA 500-F-03-223, June 2003) and incentive guidelines (EPA 500-F-01-338, August 2001) can be found on US EPA's website at

www.epa.gov/swerosps/bf/bftaxinc.htm There are also numerous case studies listed on this site as well as federal resources.

New York State Green Building Initiative credit certificates can be re-allocated to secondary users, if the initial recipient cannot utilize the entire credit amount. Information available at

www.dec.state.ny.us/website/ppu/grnbldg/index.html or Pollution Prevention Unit (518) 402-9469; NY business tax hotline (518)862-1090 x 3311

Montana Incentives for Renewable Energy <http://deq.mt.gov/Energy/Renewable/TaxIncentRenew.asp>

Virginia property tax exemptions for the Voluntary Remediation Program

<http://www.deq.state.va.us/vrp/tax.html>

US EPA's Voluntary Diesel Retrofit Program information at

<http://www.epa.gov/otaq/retrofit/retroverifiedlist.htm> Includes a list of approved retrofit technology.

Philippines Department of Natural Resources lists many tax incentive and economic incentives at

http://www.cyberdyaryo.com/features/f2004_0624_03.htm Also included are numerous links to related sites.

Western Regional Air Partnership guidance document for diesel retrofit programs can be found at

http://www.wrapair.org/forums/msf/offroad_diesel.html

Mitigation Option: Voluntary Partnerships and Pay-back Incentives: Four Corners Innovation Technology and Best Energy-Environment Management Practices (IBEMP)

I. Description of the mitigation option

This option encourages establishment of partnerships between oil and gas producers and federal, state and local agencies and with engine manufacturers. Examples of such voluntary partnerships that have worked successfully in reducing emissions and providing cost benefits to industry include the U.S. EPA's Natural Gas STAR Program, the New Mexico's Voluntary Innovative Strategies for Today's Air Standards (VISTAS) Program, Green Power and Combined Heat and Power Partnerships. The Natural Gas STAR Program is one of many voluntary programs established by the U.S. Environmental Protection Agency (EPA) to promote government/industry partnerships that encourage cost-effective technologies and market-based approaches to reducing air pollution. There are seven San Juan Basin producers¹ that are currently active members of the Natural Gas STAR Program. The VISTA Program is modeled after Natural Gas STAR.

This option involves establishing new partnerships or extending existing partnerships that encourage voluntary measures that reduce emissions and provide industry payback through improved operation and maintenance efficiencies. The IBEMP option is based on and is intended to extend upon the successes achieved in EPA's Natural Gas STAR Program and to complement the newly established VISTAS Program.

The central ideas of this option

- Increasing efficiency will result in more productivity, less emission, and increased revenue.
- Complementing EPA's Natural Gas STAR Program and VISTAS program to focus on the pollutants not covered in these programs
- Collection and use of the Best Management Practices (BMPs) from around the world, latest innovative technologies, and innovative solutions found by IBEMP members.

The air quality benefits include reduction of criteria pollutants such as NO_x, SO₂, PM_{2.5}, PM₁₀ as well as green house gases CO₂ and CH₄. The success of the EPA's Natural Gas STAR Program is well documented. According to the EPA's Gas Program, "Since the Program's launch in 1993, Natural Gas STAR Partners has eliminated more than 220 billion cubic feet (Bcf) of methane emissions, resulting in approximately \$660 million in increased revenues." One Natural Gas STAR Partner has achieved the 18% to 24% fuel saving and reduction of 128 Mcf of methane emission per unit per year after installing an automated air to fuel ratio (AFR) control system called REMVue. According to engine manufacturers, new generation engines have benefits over older generation such as low operating cost, high thermal efficiency, low emissions, maintenance simplicity, and low repair cost which will help in recovering the cost of investment faster. An example of rapid improvement in the engine technology is the new Cummins-Westport engine, which is capable of peak thermal efficiency of close to 40% with 0.01 g/bhp-hr PM and 0.2 g/bhp-hr NO_x emission. Even though Cummins-Westport engines and new generation engines from other engine manufacturers are geared towards transportation sector at present because of tighter emission standards, the improved engine technologies will help reduce the pollution in the other industrial sectors as the demand grows for efficient engines.

¹ BP, Burlington Resources, ConocoPhillips, Devon Energy, Williams Production, Energen Resources, and XTO Energy

Under this option, the time period to offset the cost of the replacing old engines with a new generation engines can be estimated through analysis of data from laboratory testing. Such data may be available from engine manufacturers or obtained through independent laboratory engine performance tests. The voluntary comparative laboratory performance and emissions testing (e.g., operating cost) and documentation would be performed by an independent test laboratory. In addition, voluntary laboratory and field-testing of a select group of existing engines (e.g., uncontrolled small, < 300 hp, engines) could provide a means to identify cost-effective modifications to improve engine efficiency and reduce engine emissions (Lazaro 2006, SERP).

Under this program the increased revenue from methane mitigation and fuel and maintenance savings can offset the cost of investment in the BMP and new technologies or equipment. In addition, under the proposed IBEMP option, partner members' mitigation efforts will be fully recognized and promoted similar to the recognition of partner contributions under EPA's Natural Gas STAR Program and New Mexico's VISTAS Program. Mitigation efforts can be recognized through awarding of emission credits (which can be traded in an emission market system, OOT-3). These efforts will also provide benefits to members through improved public and investor relations.

Since the IBEMP option is a voluntary program, participating members will have control or choice on mitigation decisions that are made. This provides opportunities for choices that provide a return on investments in best management practices and on new equipment and technology. As such, this option does not impose a burden on participating partners. Although, being a partner under this option would not relieve an operator from complying with non-voluntary measures or options, BMPs or other commitments made voluntarily under this option may facilitate compliance with other mandatory measures that may be adopted or come into play.

II. Description of how to implement

- A. **Mandatory or voluntary:** The participation in the program is voluntarily
- B. **Indicate the most appropriate agency(ies) to implement:** Through the New Mexico Environment Department under or a part of its VISTAS Program and/or in partnership with the Colorado Department of Public Health and Environment. The USEPA Gas Program may also be interested in collaborative partnerships with the Four Corners Air Quality Task Force.

III. Feasibility of the option

- A. **Technical:** The success of the EPA's Natural Gas STAR Program is a clear indicator of the technical feasibility of this program.
- B. **Environmental:** The Best Management Practices, including equipment upgrades are well established in the oil and gas industry and adoption of these measures will provide opportunities for significant and achievable emission reductions.
- C. **Economic:** This program is economically feasible because innovative technologies and BMPs will result in increased productivity, fuel saving, and environmental benefits, which in return offset the cost of investment. The previously referenced EPA Natural Gas STAR Program example illustrates that significant savings can be achieved in reduced fuel consumption (e.g., in one case that covered 51 engines reduction in excess of 2,900 MMcf or an average of 78 Mcf per day per engine, when adjusted for load, was achieved over a two-year period). The final payout period was 1.4 years by taking into consideration of fuel saving of \$4.35 million at a nominal value of \$3/Mcf.

IV. Background data and assumptions used

- 1. United States Environmental Protection Agency (USEPA) Natural Gas STAR Program
<<http://www.epa.gov/gas/>>

2. New Mexico San Juan Voluntary Innovative Strategies for Today's Air Standards (VISTAS)
<<http://www.nmenv.state.nm.us/aqb/projects/SJV/index.html>>
3. Engine Manufacturers: <www.cat.com>, <www.cummins.com>, <www.cumminswestport.com>.
4. Argonne National Laboratory, Strategic Emission Reduction Plan, Draft, 2006
5. Near-term commercial availability of small clean efficient engines
6. Near-term commercial availability of advanced engine technology

V. Any uncertainty associated with the option Low to medium.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups

Establishing and implementing an effective IBEMP is the facilitation of voluntary participation of San Juan oil and gas producers. There are no key crossover issues with other source groups.

Mitigation Option: Voluntary Programs

I. Description of the mitigation option

Overview

This option describes voluntary programs to implement mitigation strategies and achieve air quality benefits that are above and beyond the requirements of regulations and permits. This option is not meant to replace the *Voluntary Partnerships and Pay-back Incentive* mitigation option, nor is this option meant to indicate voluntary implementation should be applied to existing or future requirements necessary for improvement of air quality. There are situations in which mandatory measures are the only system that will result in emissions reductions that are high-impact, consistent, and necessary. There are also situations in which voluntary implementation of strategies may be a method to achieve emissions reductions in a time- and cost-effective manner. Voluntary programs allow participants to demonstrate their commitment to the issue and to local communities. Challenges to success with voluntary programs include publicizing a program to make it well-known, creating a list of strategies and technologies that may be implemented voluntarily, offering incentives sufficient to attract program participants, and quantifying emissions reductions adequately and consistently to estimate results.

Air Quality and Environmental Benefits

- Air quality improvement because voluntary measures would achieve emissions reductions beyond regulatory and permitting requirements.
- Depending on strategy/technology, other environmental benefits may exist.

Economic

- Capital investment from participants for voluntary measures and reporting.

Trade-offs

- Air quality improvement
- Positive public relations
- Agency's costs for administration and tracking.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary. The New Mexico Environment Department already administers a voluntary program called VISTAS (Voluntary Innovative Strategies for Today's Air Standards) that is modeled after EPA's Natural Gas STAR Program. To increase implementation, the agency could compile a list of mitigation options not otherwise required by regulation or permit, as a list of "qualifying" voluntary measures for VISTAS. More information about VISTAS is available at:

<http://www.nmenv.state.nm.us/aqb/projects/SJV/index.html>. Quantification of benefits and measurement of other results is essential to ensure accountability in a voluntary program and increase likelihood of success of the program. In addition, participants or the administrator of a voluntary program should describe voluntary actions by producing "Lessons Learned" papers, which are short descriptions of practices and technologies employed, benefits and challenges, feasibility, and implications for future use of the same voluntary actions.

B. Indicate the most appropriate agency(ies) to implement: State Environmental Agencies

III. Feasibility of the option

A. Technical: Good feasibility due to flexibility and choices regarding participation and specific technology(ies) implemented. Potential voluntary measures for the oil and gas industries may include, but are not limited to, the following:

- Plunger lift cycles for removal of liquid buildup and minimizing well blowdowns.
- Device on tanks to control over-heating, such as bands of insulation.
- Electrification where possible.
- Centralization of tank batteries to decrease truck traffic.

B. Environmental: Excellent feasibility, however environmental benefits depend on control strategies. Select control strategies may have other air or non-air environmental impacts, such as SCR's ammonia slip.

C. Economic: Feasibility depends on incentives. Economic feasibility often increases in response to incentives. Participation in voluntary programs for companies is often based on a cost/benefit economic analysis, and incentives can provide a deciding factor. Potential incentives would be determined by the implementing agency and may include the following:

- “Good Citizen” marketing
- Alternative to regulation, if any exist
- Paybacks/savings
- Consideration for expedited permits, if possible
- Parametric monitoring less strict or other requirement leniency, if possible
- Tax credit/royalty rate reduction
- For Federal land, modification in standard stipulations, if possible.
- “Credit” given like an Environmental Management System on compliance history

IV. Background data and assumptions used

Natural Gas STAR and San Juan VISTAS, both voluntary air programs in the Four Corners region.

V. Any uncertainty associated with the option High. Voluntary programs do not guarantee emissions reductions, nor are emissions reductions enforceable. Quantify of reductions through reporting may lessen uncertainty but do not guarantee or enforce reductions.

VI. Level of agreement within the work group for this mitigation option Medium. This option write-up stems from a discussion at the November 8, 2006 meeting of the Oil and Gas Work Group.

Some members of the work group expressed concern that mandatory application of the strategies outlined in this document prior to analysis by a regulatory agency may preclude consideration of advantages and disadvantages from voluntary programs. There was also some discussion of the concept of criteria for establishing whether a mitigation strategy is applied under voluntary or mandatory conditions should be developed to enhance capability for implementation of the options. These criteria would provide an important tool to agencies considering options by better defining feasibility. Additionally, voluntary application of the mitigation strategies would facilitate the development and efficient implementation of these options via a “lessons learned” approach where mandatory application may prematurely dictate the method of implementation.

VII. Cross-over issues to the other source groups

If a voluntary program has a wide range of participants, there are many cross-over issues to other source groups in terms of what voluntary measures could be implemented by those sources.

Mitigation Option: Cumulative Inventory of Emissions and Required Control Technology

I. Description of Mitigation Option

The Four Corners Region is a hotbed of oil and gas activity. There are more than 20,000 oil and gas wells in the San Juan Basin and at least 12,500 additional new wells are proposed within the next 20 years. Oil and gas facilities are being located in remote areas and in neighborhoods and cities. The City of Bloomfield, NM, population of 7,200 people, has at least six major oil and gas processing facilities in very close proximity. A large elementary school near the cluster of these facilities north of Bloomfield was evacuated in 2006 due to an accidental release of noxious emissions from one of these gas plants.

A cumulative inventory of total emissions from the large oil and gas facilities near densely populated areas should be conducted prior to the permitting of additional facilities. It has been reported that at least one new, large, petroleum processing facility is on the drawing board for the Bloomfield area.

All oil and gas facilities, large or small, should be required to report all emissions to appropriate governing agencies annually. A cumulative inventory of emissions is necessary.

Installation of best available technology emission control equipment on ALL oil and gas facilities should be MANDATORY to greatly reduce the release of pollutants into the environment. All internal combustion engines should be required to be fitted with catalytic converters.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory.

B. Indicate the most appropriate agency (ies) to implement: States of New Mexico and Colorado.

III. Feasibility of the option

A. Technical: is not clear whether the intent was to have a yearly report of emissions output based on continuous emissions monitoring for all pollutants (very expensive), or if the intent was to have the operators estimate the amount of emissions based on what sources had been operational during the year. Option also needs to define what levels of the given pollutants would be acceptable to assess feasibility.

B. Environmental: None

C. Economic: None

IV. Background data and assumption used

Bloomfield area ozone levels are already periodically high according to monitoring. Any consideration of permitting additional large oil and gas facilities near Bloomfield should include risk of increasing levels of ozone.

An example:

The North Crandall Compressor Station located within the City of Aztec is permitted by NMED Air Quality Bureau at 176.3 tons/yr (tpy) of Nitrogen Oxides (NOX), 39.4 tpy of Carbon Monoxide and 75.9 tpy of Volatile Organic Compounds (VOC's). There is a warning sign on the fence that states "Warning Hazardous B.T.E.X. emissions may be present." B.T.E.X. compounds are toxic to humans and wildlife. Several homes are located near this facility.

In comparison to the refineries and gas processing facilities in the Bloomfield area, the Williams Crandall Compressor Station is small but it is permitted to emit about 292 tons of pollutants per year into the atmosphere. Cumulative permitted emissions from the very large Bloomfield facilities are unavailable at this time.

Oil and gas facilities are sources of many hazardous pollutants such as NOX, SOX, VOC's, methane, hydrogen sulfide, etc. Many of these pollutants contribute to respiratory diseases, cardiac diseases and some of them are carcinogens. Hydrogen sulfide is a deadly neurotoxin.

V. Any uncertainty associated with the option None.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups TBD.

Mitigation Option: Mitigation of Hydrogen Sulfide

I. Description of Mitigation Option

Hydrogen sulfide (H₂S) is a deadly neurotoxin. Since H₂S contamination is becoming more widespread, for the safety of the public and the oilfield employees ALL wells should be tested for H₂S by the well operators at least twice per year and the test results reported to appropriate agencies.

The companies provide H₂S training and monitors for the employees. The employees are trained to be aware of H₂S, but the general population is not. The typical rotten egg smell is a familiar warning to oilfield employees, but the general population who lives in close proximity to H₂S wells are not informed about the dangers of an H₂S release.

Public information programs on the dangers and toxicity of oil and gas pollutants and most importantly H₂S, must be made available to the people. Ideally, gas wells and refineries should be isolated away from the general population; however, oil and gas facilities are being established in populated areas and vice versa. Houses are being built next to oil and gas sites. For the health of the public, exposure to H₂S and other petroleum related toxics must be prevented.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory.

B. Indicate the most appropriate agency (ies) to implement: The companies and the States of New Mexico and Colorado.

III. Feasibility of the option

Not considered.

IV. Background data and assumption used

For H₂S information, do a Google search on Dr. Kaye H. Kilburn MD, and Professor of Medicine at the University of Southern California. He is a leading researcher on chemicals such as hydrogen sulfide and diesel exhaust.

The Bureau of Land Management has been collecting data on the wells contaminated by hydrogen sulfide in the San Juan Basin.

Quick statistics are as follows:

- More than 375 wells test positive for H₂S
- H₂S is present in at least 5 formations
- 11 producers have reported H₂S wells
- A lot of the small producers did not report, so these numbers are likely higher.

Sour gas (H₂S) fields are common in Colorado and New Mexico. New Mexico has a State Regulation with an ambient air quality standard for H₂S; however, it is reported that NMED does not have H₂S measuring equipment. H₂S must be closely monitored and controlled by the companies and the State and Federal agencies. It can be deadly.

V. Any uncertainty associated with the option TBD.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups TBD.

Mitigation Option: Encourage States Importing San Juan Basin Natural Gas to Require Pollution Control at the Source

I. Description of the mitigation option

States that import San Juan Basin natural gas should require the gas be produced and transmitted in an environmentally clean method. End users should have a responsibility for the sources of pollution generated from natural gas production.

Recent California legislation banning importation of power from sources that generate more greenhouse gases than in-state natural gas-fired plants leads to this related issue.

Much of the natural gas used in these plants as well as in the residential sector is imported from other states or other countries. One published article¹ states that 85% of the natural gas used in California is from out-of-state and that one-quarter of this comes from the San Juan Basin. Other states may also be using San Juan Basin natural gas. It is disingenuous for states to claim to be producing clean power or using clean gas for residential use when the production of fuel for that “clean” power plant or clean burning appliance is creating serious air and water quality problems at the source of the fuel. If the user states are seriously concerned about improving air and water quality they should address out-of-state impacts as well as in-state impacts.

II. Description of how to implement

A. Mandatory or voluntary:

Adoption of a “clean fuel import policy” by user states would necessarily have to be voluntary. However, the application of such a policy by a user state, once adopted, could and should be mandatory for fuel importers.

B. Indicate the most appropriate agencies to implement:

Implementation of the policy in user states could be by the regulatory agencies or commissions charged with oversight of investor-owned or publicly-owned electric utility systems. In some cases legislation may be necessary to implement this policy.

There is a need to develop an inventory, state-by-state, of customers who are importing natural gas from wells in the San Juan Basin. The first step in implementation would involve contacting user states and urging adoption of policy or legislation requiring importation of “clean” natural gas; a definition of “clean” must be developed.

III. Feasibility of the option

A. Technical:

It may be difficult to develop a good working definition of what constitutes acceptably “clean” natural gas. This is also a legal issue and one must work within the framework of the Federal Clean Air Act and Clean Water Act as well as individual state statutes.

B. Environmental:

Should be feasible

C. Economic:

Could eventually lead to higher costs for electricity in user states due to the rightful inclusion of environmental costs of fuel production.

D. Political:

Could be very difficult to implement in some states

IV. Background data and assumptions used

Assumption that most natural gas produced in the San Juan Basin is exported to other states. The figures cited in Section I should be checked/verified.

V. Any uncertainty associated with the option

Yes; response of user states unknown.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other Task Force work groups

Significant cross-over to the Power Plants and Oil & Gas Work Groups

¹ *High Country News*, Dec. 25, 2006, p. 12.

OIL & GAS: PUBLIC COMMENTS

Oil & Gas Exploration & Production Public Comments

Comment	Mitigation Option
If "many companies BMPs in place already," then why does a mandatory approach to BMPs seem implausible. This should be a cost of doing business in this area; a cost that is well-absorbed by most other companies.	Best Management Practices (BMPs) for Operating Tank Batteries
VRU's have one big technical problem not addressed, the introduction of air in the gas. Air is made up of Nitrogen and Oxygen two contaminants that the gas pipeline companies refuse to take into their system. If one VRU allows air to enter the gas system, then the whole gas system must be shut down or flared in the field. The gas companies must be forced to take air in reasonable quantities into their system. The gas pipelines will argue that it is unsafe, if that is true then all the gas supplying houses in the Colorado front range must be shutdown because air is added to improve quality.	Installing Vapor Recovery Units
In the 60's and 70's this type of water removal was tried in the northern Rockies. The amount of saltwater disposal was huge and the beds may only last a day or two before they must be changed.	Dehydrators / Separators / Heaters
Glycol pumps are a critical item and any replacement system must have a high reliability. 5KW generators will had NOx, CO, CO2 and decrease reliability. Kimray pumps with flash gas separators reduce emissions and keep the system reliable. the gases recovered from the pump gas separator can be used for fuel MOST of the time. In some cases where the gas stream is high in liquefiable hydrocarbons (those with molecular weights higher than 40) the pump gas separator vapors will not burn reliably or completely cause unreliable operators and increased emissions. In the case of gases with high liquefiable content, vent gases need to be flared (burned).	Zero Emissions (a.k.a. Quantum Leap) Dehydrator
We strongly agree that an initial voluntary monitoring effort, followed by mandatory reporting and monitoring requirements, should be initiated by the operators to measure concentrations and species of VOCs and HAPs and other flaring by-products.	Venting versus Flaring of Natural Gas during Well Completions
We strongly agree that co-location and centralization of new oil/gas field facilities should be voluntarily implemented by operators. We also agree with the approach of state and federal agencies and mineral management agencies proactively integrating this approach into planning and permitting processes.	Co-location / Centralization for New Sources
The present laws will not allow this option. TEG (glycol) units must be permitted at a maximum rate. In the Rockies the maximum rate is only required for a few months during the year. Good operators adjust their pumps as needed to save fuel and lower emissions, but they get not credit for doing so because their permits are set. GLYCALC uses all kinds of default assumptions, this does not replace good engineering and the ability to make real life adjustments. Other design and simulation programs should be allowed without any legal ramifications.	Control Glycol Pump Rates
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Control Glycol Pump Rates
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Convert High-Bleed to Low or No Bleed Gas Pneumatic Controls
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Optical Imaging to Detect Gas Leaks

Comment	Mitigation Option
Instrument gas or instrument air is used to control facilities. These controls maintain the emission control system, gas quality controls and safety shutdown systems. If the instruments air/gas system lacks sufficient quantity and quality, the controls will fail and emissions, quality and safety devices can fail with undesirable results. At small and remote sites air compressors will be unreliable and gas must be used.	Convert Gas Pneumatic Controls to Instrument Air

Oil & Gas Stationary RICE Public Comments

Comment	Mitigation Option
The SUGF agrees that new air quality management strategies such as this option should be implemented to address cumulative air quality impacts. It is highly recommended that this option be considered by the regulatory agencies and be applied to both new and existing engines, particularly units of less than 300 horsepower. Although horsepower levels are lower and operating hours may be limited, emission rates of these smaller units are higher than larger units. As a single source, emissions may be minimal, but collectively with other area sources it may have a cumulative affect.	Industry Collaboration
<p>Comments below are specific to the mitigation option as currently written, which assumes the power requirement would come from the power grid. A second alternative is also provided below as a sub option assuming the power comes from on-site generators. We recommend including both alternatives to this option. Comments are also provided on the analysis of this option under the cumulative effects section of the public draft report.</p> <p>Install Electric Compression (re-label as Alternative 1 - Power Grid, see recommended Alternative 2 addition below after comment # 6)</p> <p>1. The overview is not consistent with overviews written for other mitigation options covered in the Task Force Report. As written, the overview presents a rather biased view on the viability of this option. The overview should provide a description of the option without any discussion about the option's technical or economic feasibility. Possible physical restriction or modification requirements on installation for specific compressors should be removed and discussed under Sec III. Feasibility of the option, A. Technical. The last two sentences on the electric grid should also be moved to the feasibility discussion or deleted.</p> <p>Under the mitigation option overview, we recommend inserting the following:</p> <p>The selection of combustion engines for electric compression should be on case-by-case basis which will allow the flexibility of evaluating necessary compressor interface modifications such as re-gearing to accommodate electric motors.</p> <p>2. The discussion and emission table under Air Quality/Environment is inconsistent with discussions covered in the other mitigation options and should be deleted. Please see our comments on the Cumulative Effects section analysis of this option. The nationwide averages of emissions from power plants operated by the three identified companies would not be representative of the power supplied from the Western Power Grid.</p> <p>We recommend inserting the following under the mitigation option overview:</p>	Install Electric Compression

Comment	Mitigation Option
<p>The noise from continuously running internal combustion engines can be an issue for the nearby residents. The switch to electric motors will also help cut down the noise in the oil and gas operation.</p> <p>3. The economics as written only covers the costs of the option if implemented. To provide a balance picture both costs and economic benefits should be covered. The following points should be included in the discussion:</p> <ul style="list-style-type: none"> a. In case of electric motors connected to power grid, there is virtually no maintenance cost. b. The electric rates in the night are cheaper compared to peak times. This will result in additional saving for oil and gas industry. c. The need for less maintenance of electric motors and localized electric grid will result in fewer maintenance trips for the oil and gas workers which will help in controlling dust as well as minimize impact on the wild area in the four corners region. <p>In the second bullet not sure what specific maintenance and repair costs we be borne by producers that are associated with the electric power source for electric compression. Maintenance and repair of substations and transmission lines, from the grid to substation, are typically borne by electric generators and included in rates to consumers.</p> <p>The last bullet on suppliers/manufacturers is more an implementation issue than an economic issue. We recommend moving this discussion to description on how to implement.</p> <p>4. Tradeoffs - We recommend striking any reference to new co-generation plants as means to supply power for electric compression, since the electric compression option requires no thermal power. As previously stated current plans for electric power generating within the western regional power grid should be adequate to meet even the most optimal electric compression demand that might develop.</p> <p>5. Burdens - Since implementation of electric compression is voluntary the producers can evaluate which compressor conversions to electric are economically feasible. Economic burdens over the long term can be minimized and possibly turned into economic gain based on careful evaluation of return on capitol expenditures (e.g., lower electric motor vs. RICE engine maintenance costs). The assumed requirement for new electric power generation to support electric compression is speculative, since the degree of implementation of this option producer specific. We recommend deleting the sentence on capitol investment for new power plants. Also, existing plans for new generation may be sufficiently adequate to meet reasonably anticipated power requirements for implementing this option. We recommend consultation with the Power Plant Workgroup.</p> <p>6. II. Description of how to implement and feasibility of option - See above comments.</p> <p>7. III. Feasibility of the option, C Economics - On economics, we agree that costs need to be evaluated, including the economic benefits, as previously mentioned. The need for modeling (air quality) to evaluate the air quality</p>	

Comment	Mitigation Option
<p>benefits is true about all of the options. Also, the planned modeling to address cumulative regional air quality impacts is discussed elsewhere in the draft report. We recommend deleting the sentence.</p> <p>ON-SITE ELECTRIC GENERATOR ALTERNATIVE TO GRID POWERED ELECTRIC COMPRESSION</p> <p>As written the current option identifies only one source of electric power, power from the grid. A second alternative to this option would be to supply power to the electric motors using local dedicated low-emission natural gas lean-burn electric generators. The electric compression using the lean-burn electric generator should be included as a second alternative for the "Install Electric Compression" mitigation option.</p> <p>We recommend that the Four Corners Air Quality Task Force add the following language to the Install Electric Compression mitigation option:</p> <p>Mitigation Option: Install Electric Compression (Alternative - On-Site Generators)</p> <p>I. Description of the mitigation option</p> <p>Overview - As an alternative to grid power dedicated on-site natural gas-fired electrical generators can be used to supply power to electric motors that replace the selected RICE compression engines. The electric motors would be rated at an equivalent horsepower to that of RICE engines currently used for gas compression. The power sources for the electric compression could consist of a network of on-site gas-fired electrical power generators. The alternative could be expanded to include consideration of replacement of other engines, such as, gas-fired pump-jack engines used as "prime-movers."</p> <p>The currently available gas electric generator run on variety of fuels including low fuel landfill gas or bio-gas, pipeline natural and field gases. The gas electric generators are available in the power rating from 11 kW to 4,900 kW. Decisions on the use of on-site generators to replace natural gas-fired engines and the number of generators required would depend on a number of factors, including the proximity, spacing and size of existing engines. As a simple example using the conversion factor of 1 MW = 1,341 HP, adding a 1 MW natural gas-fired generator could replace an inventory of approximately 33 small (40 hp) internal combustion engines if these were reasonably close proximity, say spaced within a one or two mile radius. However, in "real world" operations, there will be several factors involved in determining the number of required gas-fired electrical generators; such as transmission loss, ambient operating temperature, load operating conditions, pattering of applied loads, etc.</p> <p>Air Quality/Environmental Benefits</p> <p>The emissions from gas electrical generators are relatively low compare to smaller internal combustion engines because of new technology and ability of controlling emission from big engines. For example a Caterpillar G3612 gas electrical generator with power rating of 2275 kW emits 0.7 gram/hp-hr NOx at 900 rpm which is equivalent to 0.0009387 g/W-hr. For comparative illustration with alternative 1, if you assume As stated in the mitigation</p>	

Comment	Mitigation Option
<p>option; "Control Technology Options for Four Corners Power Plant" (FCPP), the NOx emission from FCPP is approximately 0.54 g/mmBtu. Based on the assumption that efficiency of FCPP is 40%, the NOx emission from FCPP is approximately 0.002099 g/W-hr. This comparison shows that the gas electrical generator is more environmentally friendly than using power from a coal based power plant. The baseline average emission for the Western Grid should be used to calculate the real emission difference between installing a lean burn electric generator to replace combustion engines.</p> <p>The noise from continuously running internal combustion engines can be an issue for the nearby residents. The switch to electric motors will also help cut down the noise in the oil and gas operation.</p> <p>The need for less maintenance of electric motors and lean burn electric generator will result in fewer maintenance trips for the oil and gas workers which will help in controlling dust as well minimize the impact on wild area in the four corners region.</p> <p>Economics</p> <p>The initial capital cost of installing gas electrical generator and electrical motor would be relatively high. As an example, a generator of 1 MW capacity can approximately support 33 combustion engine of 40 HP. A general purpose 40 HP engines costs about \$1200.00 which results in capital cost of \$39,600 for replacing 33 internal combustion engine with electric motors. The approximate cost of a 1.2 MW gas-fired generator is \$430,000. The total capital cost for replacing 33 engines with a gas fired generator will be about \$470,000. However in long term the benefit in terms of emission reduction and saving in maintenance cost should help in recovering the initial capital cost.</p> <p>The maintenance cost of one big generator is cheaper than maintenance of many smaller internal combustion engines.</p> <p>The cost of running electrical wires to connect electric motors will much less than currently installed pipelines to carry natural gas for the small rich burn combustion engines.</p> <p>Tradeoffs</p> <p>In case of gas electric generators, there will be shift of emission from many internal combustion engines to one or several big internal combustion engine(s). There would be a net reduction in emissions which will depend on degree of conversion that each producer deems economically feasible.</p> <p>The cost and affects of running transmission lines from generator(s) to power electrical motors for gas compression needs to be evaluated.</p> <p>Burdens</p> <p>The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry.</p> <p>II. Description of how to implement</p>	

Comment	Mitigation Option
<p>A. Mandatory or voluntary: Voluntary, depending upon the results of monitoring data over time.</p> <p>B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies.</p> <p>III. Feasibility of the option</p> <p>A. Technical: The feasibility mainly depends on the close proximity of replaceable internal combustion engines and operating conditions of internal combustions engines in order of selection of gas electrical generator. The power, transmission line and substation requirements for on-site lean-burn generator system would need to be carefully considered in deciding the feasibility of this option.</p> <p>B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Emissions from on-site electric generators would more than off-set the natural gas-fired engines that could be targeted for replacement (e.g., uncontrolled compressor engines or small rich burn pump jack engines).</p> <p>C. Economic: Depends upon economics of ordering electrical motors, the ability of the grid system to supply the needed capacity and the cost to obtain right of way to drop a line to a potential site. Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small.</p> <p>IV. Background data and assumptions used</p> <p>The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff.</p> <p>Gas electrical generator information was obtained from Caterpillar's Website.</p> <p>V. Any uncertainty associated with the option (Low, Medium, High):</p> <p>Medium based upon uncertainties of obtaining electrical easements from landowners and/or land management agencies.</p> <p>VI. Level of agreement within the work group for this mitigation option TBD</p> <p>VII. Cross-over issues to the other source groups (please describe the issue and</p>	
<p>The SUGF agrees that implementation of this federally mandated level of emission control will minimize emissions from newly manufactured, modified and reconstructed engines after their respective effective dates.</p>	<p>Follow EPA New Source Performance Standards (NSPS)</p>

Comment	Mitigation Option
<p>The SUGF supports the control technology options listed above as the SUGF supports usage of Best Available Control Technologies on internal combustion engines located within the exterior boundaries of the Southern Ute Indian Reservation.</p>	<p>Use of SCR for NOx control on lean burn engines Use of NSCR / 3-Way Catalysts and Air/Fuel Ratio Controllers on Rich Burn Stoichiometric Engines Use of Oxidation Catalysts and Air/Fuel Ratio Controllers on Lean Burn Engines Install Lean Burn Engines</p>
<p>As EPA commented on the Cumulative Effects Paper, it is unclear how the 4 Corners Task Force Interim Emissions Recommendations for Stationary RICE are being implemented.</p> <p>The mitigation option <u>Interim Emissions Recommendations for Stationary RICE</u> states that "BLM in New Mexico and Colorado are currently requiring these emission limits as a Condition of Approval (COA) for their Applications for Permits to Drill (APD). These limits currently apply only to new and relocated engines ... (compressors assigned to the well APD)..." However, we understand that BLM policy for a small engine COA as applied to an APD is for new and replacement engines.</p> <p>The Oil and Gas Workgroup should clarify how is the terms "relocated" and/or "replacement" are being defined by BLM and the USFS with respect to COAs for well located engines.</p> <p>For comparison, EPA's NSPS for spark ignition engines will apply to new, modified, and reconstructed units starting in January 2008. The terms new, modified, and reconstructed are defined in Federal Regulation.</p>	<p>Interim Emissions Recommendations for Stationary RICE</p>
<p>We recommend adding the following next generation technology to the four currently included in this mitigation option:</p> <p>Homogeneous-Charge Compression-Ignition (HCCI) technology was analyzed the by cumulative effects workgroup but was inadvertently omitted from the oil and gas work group mitigation option paper Next Generation RICE Stationary Technology. The following is a recommended text for inclusion in the Final Report:</p> <p>Homogeneous-Charge Compression-Ignition (HCCI) Engine</p> <p>I. Description of the mitigation option</p> <p>Overview</p> <p>Homogeneous charge compression ignition (HCCI) engines are under development at several laboratories. In these engines a fully mixed charge of air and fuel is compressed until the heat of compression ignites it. The HCCI combustion process is unique since it proceeds uniformly throughout the entire cylinder rather than having a discreet high-temperature flame front as is</p>	<p>Next Generation Stationary RICE Control Technologies – Cooperative Technology Partnerships</p>

Comment	Mitigation Option
<p>the case with spark ignition or diesel engines. The low-temperature combustion of HCCI produces extremely low levels of NOx. The challenge of HCCI is in achieving the correct ignition timing, although progress is being made in the laboratories.¹</p> <p>Only a few experimental measurements of NOx from (HCCI) engines have been reported. The measurements are typically reported as a raw NOx meter measurement in parts per million rather than being converted to grams per horsepower-hour. Dibble reported a baseline measurement of 5 ppm when operated on natural gas.² Green reported NOx emissions from HCCI-like (not true HCCI) combustion of 0.25 g/hp-hr.³ The achievable NOx emission levels are yet to be determined. It is not currently known if HCCI technology can be applied to all engine types and sizes. However, if all reciprocating engines could be converted to HCCI so that the engines produce no more than 0.25 g/hp-hr, then the overall NOx emissions reduction would be 80% in both Colorado and New Mexico using the calculation methodology of the SCR mitigation option.</p> <p>II. Description of how to implement</p> <p>A. Mandatory or voluntary</p> <p>It is too early to determine whether implementation of this technology will be voluntary or mandatory.</p> <p>B. Indicate the most appropriate agencies to implement</p> <p>III. Feasibility of the option</p> <p>A. Technical - HCCI is in the laboratory stage of development.</p> <p>B. Environmental - HCCI has the potential of extremely low NOx levels.</p> <p>C. Economic - HCCI is not sufficiently developed to have proven economic feasibility.</p> <p>IV. Background data and assumptions used</p> <p>1. Bengt Johansson, "Homogeneous-Charge Compression-Ignition: The Future of IC Engines," Lund Institute of Technology at Lund University, undated manuscript.</p> <p>2. Robert Dibble, et al, "Landfill Gas Fueled HCCI Demonstration System," CA CEC Grant No: PIR-02-003, Markel Engineering Inc.</p> <p>3. Johney Green, Jr., "Novel Combustion Regimes for Higher Efficiency and Lower Emissions," Oak Ridge National Laboratory, "Brown Bag" Luncheon Series, December 16, 2002.</p> <p>V. Any uncertainty associated with the option (Low, Medium, or High)</p> <p>HCCI has high uncertainty.</p>	

Comment	Mitigation Option
<p>VI. Level of agreement within the work group for this mitigation option</p> <p>VII. Cross-over issues to the other source groups (Please describe the issue and which group.)</p>	

Oil & Gas Overarching Issues Public Comments

Comment	Mitigation Option
<p>The Four Corners Air Quality Task Force (4CAQTF) is a noble way of beginning communication between our citizenry and the polluting industries. Hopefully some meaningful "common ground" can be reached that will produce measurable air quality improvements.</p> <p>With a demonstrated failure of industry to "want to do their best" and when the "dollar gain" in a corporation's quarterly report is the measuring stick for it's shareholders, the recommendations from the 4CAQTF is up against a mature lobby force very capable of stopping meaningful actions that will lead to measurable benefits to our air quality!</p> <p>Therefore, spending serious time deliberating measurable benefits that could predictably occur if industry's suggestion of "year round" drilling EVERYWHERE as a means of ameliorating their emissions to me, seems without merit. A simple catalytic converter on each of their established fossil fuel operated engines would be considered a "wonderful start" of industry wanting "to do their best".</p> <p>Recommending to any state or federal land wildlife management agency to consider removing established seasonal habitat protection bans for the assumed benefit of distributing annual air quality pollutants should not be an option. Many years were spent by land management and wildlife management agencies formulating the habitats that need protection for identified species. The process to establish habitat closures is elaborate.</p> <p>Let us let this industry recommendation respectfully die and encourage installation of catalytic converters on industry's fossil fuel motors. This action does have measurable air quality results. As we drivers know, we are required by law to have catalytic converters on our vehicles as a way of demonstrating our contribution to improving air quality problems.</p> <p>As a recommendation, I would only suggest that if the oil and gas industry wants to recommend the lifting of this seasonal closure on identified lands, that THEY contact the state and federal agencies that have programming prerogatives over habitat and wildlife issues with their suggestion that lifting this ban would have beneficial measurable benefits for air quality concerns that outweigh wildlife concerns. The 4CAQTF should not be the "quarter back" for carrying the recommendation to state and federal habitat and wildlife agencies.</p> <p>I make these comments as a degreed wildlife biologist with 27 years of experience. Respectfully, Warren J. McNall 900 Sabena, Aztec, NM</p>	<p>Lease and Permit Incentives for Improving Air Quality on Public Lands</p>

Comment	Mitigation Option
<p>Disagree - unlike Wyoming, Colorado has a shortage of state and federal specialists to monitor impacts from oil and gas development. As a result, monitoring of oil and gas impacts to wildlife would likely not happen. Streamlining the permit process would be beneficial to operators economically, but may be at the expense of area wildlife and habitat.</p>	<p>Lease and Permit Incentives for Improving Air Quality on Public Lands</p>
<p>Regarding the paragraph:</p> <p>"Monitoring has also not been a model experience in this area. According to reports of a May, 2006, internal assessment Pinedale, Wyoming, Bureau of Land Management field office, the office neglected its commitment to monitor and limit harm to wildlife and air quality from natural gas drilling in western Wyoming. A wildlife biologist who worked in that Pinedale office, Steve Belinda, is reported to have quit his job because he and other wildlife specialists were required to spend nearly all their time in the office processing drilling requests and were not able to go into the field to monitor the effect of the thousands of wells on wildlife."</p> <p>Basically, I would suggest a more neutral approach than the quoted paragraph. It is rather forceful, without sufficient follow-up. It would help our situation if we could see whether the Farmington office is under similar pressures. Alternatively, examining the policies, rather than experiences, might make for a stronger position. For example, as the author seems to know a bit about BLM and permitting--she/he might instead look into the use of categorical exclusions (CAX) which are currently used to circumvent the environmental assessments (EA) that would normally be required to develop well fields on BLM land. (Sometimes this is also called streamlining.) How prevalent is this practice in the Four Corners, do CAX result in a lower standard of environmental review, and could this practice deleteriously impact 4C air quality?</p>	<p>Lease and Permit Incentives for Improving Air Quality on Public Lands</p>
<p>In light of the current global climate conditions, lessening our overall impact on the environment is everyone's duty to the planet and its children's future. This task force should not be in the position of negotiating away wildlife habitat in exchange for mitigating measures that ought to be a duty of the oil and gas industry as a cost of doing business on this planet.</p>	<p>Lease and Permit Incentives for Improving Air Quality on Public Lands</p>
<p>Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.</p>	<p>Economic-Incentives Based Emission Trading System (EBETS)</p>

Comment	Mitigation Option
<p>Economic-incentives based emission trading systems (EBETS) have had varying levels of success nationally and have been less successful in geographic regions where pollutants are already causing harm to human health or the environment. It can also be argued that these systems lack incentives to improve environmental quality over economics. They can be more a function of market supply and demand driving the trades, not variations in regional human and environmental health "costs".</p> <p>Multisectoral trading systems are complex, increase challenges in emissions monitoring, and environmental justice considerations become more complicated due to inequitable concentrations of source emissions and different pollutant mixing outcomes. (Regarding the federal Acid Rain Program, indeed, the nationwide level of emissions from electric utilities were halved since 1980, however, no geographic restrictions were imposed and many areas of higher pollution levels remained at higher levels.) As stated in the Task Force document, the major burden for the EBETS mitigation option would be administrative; however the full burden must be assessed and coordinated among the state agencies. Not only would comparability and tracking of different types, sizes and ages of installations be extremely complicated, multi-pollutant emissions trading is challenging to monitor and enforce.</p> <p>Although it would be impossible to have an emissions trading system that eliminates environmental injustice, a carefully designed trading system that is rigorous, far-sighted, and includes geographic restrictions would have a much better chance of reducing localized injustices to human health and/or the environment.</p>	<p>Economic-Incentives Based Emission Trading System (EBETS)</p>
<p>The proposed incentive to modify standard stipulations for federal land if it is to be the relaxing or waiving of seasonal restrictions for wildlife while promoting year round drilling should not be a part of the voluntary program. Seasonal restrictions have been written to benefit wildlife during times of the year when they are at increased risk due to weather, nesting, birthing, etc. The Wyoming experience has shown the potential negative impacts of intense drilling on wildlife, and how highly wildlife is valued by a broad range of American people. With the pressures from the increase in drilling, wells, roads, and pipelines in the Four Corners area, we can ill afford to lose the wildlife protections from the stipulations that we currently have.</p>	<p>Voluntary Programs</p>
<p>New Mexico and Colorado already have rules governing H₂S, no need to add more rules that may conflict.</p>	<p>Mitigation of Hydrogen Sulfide</p>
<p>New Mexico Environment Department does have controls for H₂S on paper, but state environmental officials have validated that the state does not have H₂S monitoring equipment.</p>	<p>Mitigation of Hydrogen Sulfide</p>
<p>Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.</p>	<p>Mitigation of Hydrogen Sulfide</p>
<p>Rules that are capable of being enforced due to adequate staffing and necessary monitoring tools are what is needed to regulate this area. More rules that cloud the issue, or are effectively toothless due to lack of enforcement infrastructure will not accomplish the goals of this task force.</p>	<p>Mitigation of Hydrogen Sulfide</p>