OIL AND GAS GREENHOUSE GAS EMISSIONS REDUCTIONS

FINAL REPORT
December 31, 2007

APPENDICES

A. Figure EX-1 and Table EX-1 from CCAG Final Report, p. EX-2

B. CCAG Recommendation ES-12 (Methane Reduction in Oil & Gas Operations (BMPs & PROs))
1) Policy Recommendation (CCAG Final Report Appendix H, pp. H-47 to H-50)
2) Summary of Initial Quantification of GHG Savings and Cost per Ton (CCAG Final Report, Att. H-6)

C. US EPA Gas STAR Program Information
1) List of Gas STAR Emissions Reduction Measures
2) Examples of Gas STAR BMPs and PROs

D. CCAG Recommendation ES-13 (CO2 Reduction from Fuel Combustion in Oil & Gas Operations)
1) Policy Recommendation (CCAG Final Report Appendix H, pp. H-51 to H-54)
2) Preliminary Quantification of GHG Savings and Cost per Ton (CCAG Final Report, Att. H-8)
3) Preliminary Analysis of CO2 Emissions from Natural Gas Fueled vs. Electrically Powered Compressors (CCAG Final Report, Att. H-9)

E. Climate Change Advisory Group Final Report, Attachment D-2: Fossil Fuel Industry Emissions

F. Policy Options for Oil and Gas Emissions Reductions (DRAFT), by D. Gomez, NMED Public Policy Fellow

G. The Economics of New Mexico Natural Gas Methane Emissions Reduction, by David S. Dixon, Department of Economics, University of New Mexico

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APPENDIX A

Climate Change Advisory Group Final Report, Figure EX-1 and Table EX-1

Figure EX-1

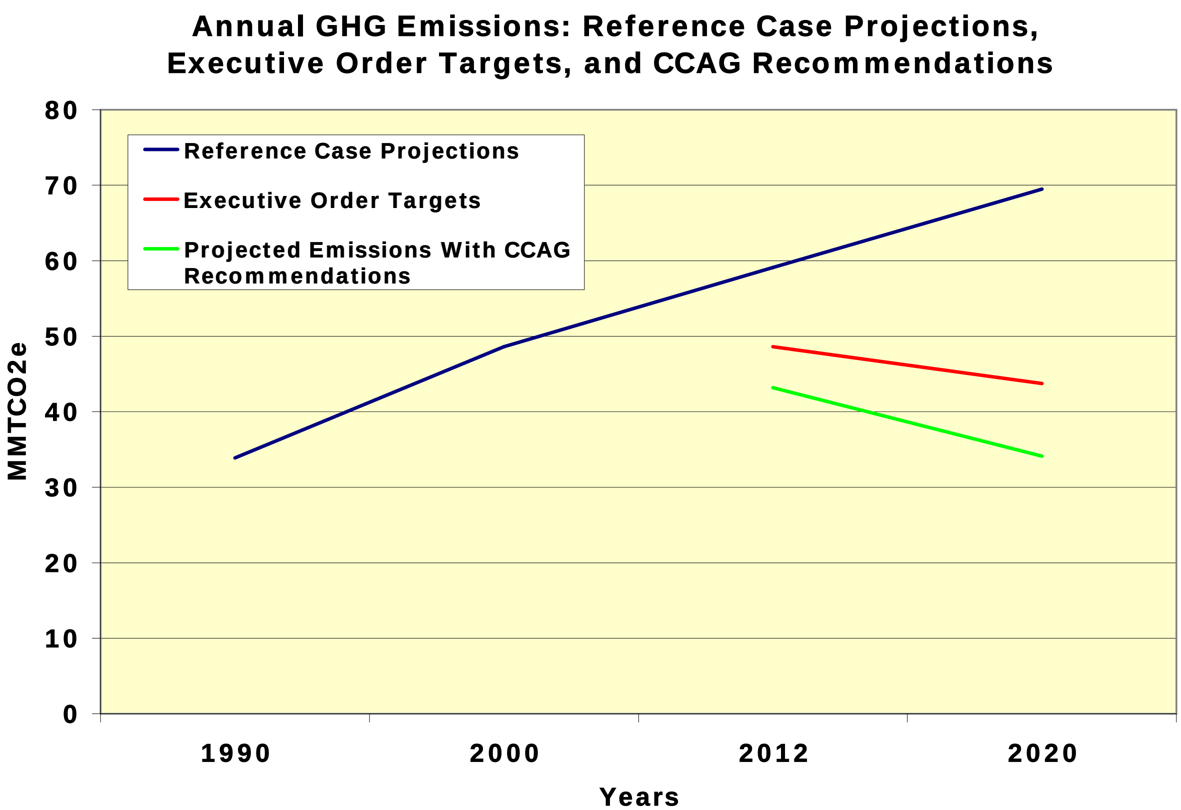

Table EX-1. Annual Emissions: Reference Case Projections, Executive Order Targets, and Impact of CCAG Recommendations

ANNUAL EMISSIONS	1990	2000	2012	2020
REFERENCE CASE PROJECTIONS	**33.9**	**48.6**	**59.1**	**69.5**
EXECUTIVE ORDER TARGETS [a]			**48.6**	**43.7**
GHG REDUCTIONS FROM CCAG RECOMMENDATIONS			***-15.9***	***-35.4***
ANNUAL EMISSIONS WITH CCAG RECOMMENDATIONS			**43.2**	**34.1**

[a] Targets aim to reduce New Mexico GHG emissions to 2000 levels by 2012, and 10% below 2000 levels by 2020.

OIL AND GAS GREENHOUSE GAS EMISSIONS REDUCTIONS

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APPENDIX B

Climate Change Advisory Group Final Report,
Recommendation ES-12 (Methane Reductions in Oil and Gas Operations)

1) Policy Recommendation (CCAG Report App. H, pp. H-47 to H-50)

2) Summary of Initial Quantification of GHG Savings and Cost per Ton (CCAG Report Att. H-6)

ES-12 Methane Reduction in Oil & Gas Operations (BMPs & PROs)

Policy Description:

<u>CCAG Summary:</u> There are a number of ways in which methane emissions in the oil and gas industry can be reduced. Natural gas consists primarily of methane, so any leaks during production, processing, and transportation/distribution should be addressed. In addition to reducing potent GHG emissions, stopping these leaks may be economically beneficial because it can prevent the waste of valuable product. The EPA Natural Gas STAR program offers numerous methods of preventing leaks. These methods, called Best Management Practices (BMPs) and Partnership Reduction Opportunities (PROs), are divided by industry sub sector (production, processing, and transportation/distribution).[9]

There are a number of ways in which methane emissions in the oil and gas industry can be reduced. Natural gas consists primarily of methane; therefore, any leaks during production, processing, and transportation/ distribution should be addressed. In addition to reducing GHG emissions, stopping these leaks may be economically beneficial because it can prevent the waste of valuable product.

The EPA Natural Gas STAR program offers numerous methods of preventing leaks. These methods, called Best Management Practices (BMPs) and Partnership Reduction Opportunities (PROs), are divided by industry sub sector: production, processing, and transportation/ distribution. Among the practices recommended are:

Preventive maintenance: Reduces emissions by improving the overall efficiency of the gas production and distribution system; minimizes the chance of leaks.

Reduce flashing losses: As the pressure on the liquid hydrocarbons in a storage tank, well, compressor station, or gas plant drops, some of the lighter compounds dissolved in the liquid are released or "flashed." Some of the compounds that are liquids at the initial pressure/temperature transform from a liquid into a gas/vapor and may be released or "flashed" to the atmosphere. The flashed gas can be captured rather than vented to the atmosphere.

Replace wet seals with dry seals on centrifugal compressors: Dry seals lead to fewer leaks than wet seals. Dry seals use high-pressure gas to seal the compressor and emit less methane, have lower power requirements, improve compressor and pipeline operating efficiency and performance, enhance compressor reliability, and require significantly less maintenance.

Compressor rod & ring replacement on reciprocating compressors: Replacing worn compressor rod packing rings and rods results in operational benefits, reduced methane emissions, and cost savings. Gas leaks from compressor rods may represent one of the largest sources of emissions at natural gas compressor stations.

[9] For a complete list, see http://www.epa.gov/gasstar/techprac.htm#tabnav

Low-bleed, air-based pneumatic devices: Replacing high-bleed devices with low-bleed devices, retrofitting, and improving the maintenance of high-bleed pneumatic devices are proven approaches to profitably reducing methane emissions. Natural gas emissions from pneumatic control devices are one of the largest sources of methane emissions in the natural gas industry.

Pump-down techniques prior to maintenance: Using fixed and portable compressors to lower pipeline pressure prior to maintenance and repair may significantly reduce methane emissions and save money. Pipeline pump-down techniques remove product from the section of pipeline under repair, thereby reducing the volume of natural gas vented to the atmosphere.

Policy Design:

The CCAG recommends that:

Subject to verification of technical and economic feasibility and reduction potential:

(a) New Mexico implement, on a voluntary basis, all BMPs, PROs, and available technologies starting in 2007 to reduce overall CO_2e emissions due to methane emissions from the oil and gas sector by ~20% by 2020;

(b) New Mexico actively promote participation by oil and gas operators in EPA's Natural Gas Star program and New Mexico's San Juan VISTAS program; and

(c) As voluntary measures are implemented, if the State determines that oil and gas operators are not on track to achieve the above goal, the State should implement mandatory approaches where appropriate. Mandatory measures would be implemented only after following formal rule making or statutory change procedures with the appropriate "due process" requirements.

- **Goal levels:** As noted above.
- **Timing:** As noted above.
- **Parties:** Oil and gas production, processing, and transportation/distribution companies

Implementation method(s):

Policies to implement these practices could include:

- Information and education.
- Technical assistance.
- Funding mechanisms and/or incentives.
- Voluntary and or negotiated agreements.
- Codes and standards – coupled with cost and investment recovery mechanisms, if appropriate.

Related Policies/Programs in place:

- Some companies practice the measures outlined above, but currently there is no state or federal requirement for any company to implement any of these practices.

Type(s) of GHG Benefit(s):

- CH4: This policy could result in substantial reductions of methane emissions in the oil and gas industry.

Estimated GHG Savings and Costs Per Ton:

The specified goal level is translated into GHG reductions below. BMPs, PROs, and other technologies and practices cover a wide variety of options, the costs of which vary significantly by site and application, and are thus difficult to consolidate. Capital cost and other information for individual technologies and practices is available at EPA's Natural Gas Star website, http://www.epa.gov/gasstar/techprac.htm#tabnav

An initial consolidation analysis of GHG savings and costs per ton was developed by Dr. Lorna Greening to assist in the Energy Supply Technical Work Group's consideration of ES-12. A summary of this spreadsheet can be found in Attachment H-6. The full spreadsheet can be accessed electronically as Attachment H-7 at http://www.nmclimatechange.us/template.cfm?FrontID=4705.

#	Policy	Scenario	Reductions (MMTCO2e)			NPV (2007–2020) $ Millions	Cost-Effective-ness $/tCO2
			2012	2020	Cumulative Reductions (2007-2020)		
ES-12	Methane reductions in oil and gas operations through BMPs and PROs	Specified goals translated into tons GHG reduced.	2.71	3.43	35.34	*Not Estimated*	*Not Estimated*

See the EPA Natural Gas Star website (www.epa.gov/gasstar/techprac.htm#tabnav) and Dr. Lorna Greening's spreadsheet analysis for additional information regarding GHG savings, costs, and cost-effectiveness.

Data Sources, Methods and Assumptions (for quantified actions):

- **Data Sources:** See the EPA Natural Gas Star website (www.epa.gov/gasstar/techprac.htm#tabnav) and Dr. Lorna Greening's spreadsheet analysis for information concerning data sources.
- **Quantification Methods:** See the EPA Natural Gas Star website (www.epa.gov/gasstar/techprac.htm#tabnav) and Dr. Lorna Greening's spreadsheet analysis for additional information.
- **Key Assumptions:** See the EPA Natural Gas Star website (www.epa.gov/gasstar/techprac.htm#tabnav) and Dr. Lorna Greening's spreadsheet analysis for additional information regarding assumptions.

Key Uncertainties:

- See the EPA Natural Gas Star website (www.epa.gov/gasstar/techprac.htm#tabnav) and Dr. Lorna Greening's spreadsheet analysis for additional information regarding uncertainties.

Contributing Issues, if applicable:

- Proportionally more natural gas would get to market rather than being consumed or lost in the production and distribution process.
- Companies increase their sales, and possibly their profits, by selling rather than wasting valuable product.

Feasibility Issues, if applicable:

- Feasibility of specific BMPs and/or PROs vary on a site-by-site basis.

Status of Group Approval:

Complete.

Level of Group Support:

Unanimous consent.

Barriers to consensus (if less than unanimous consent):

None.

Attachment H-6

ES-12 Methane Reductions in Oil and Gas Operations (BMPs & PROs) – Summary of Initial Quantification of GHG Savings and Cost per Ton

The following is a summary of an initial analysis developed by Dr. Lorna Greening to assist in the Energy Supply Technical Work Group's consideration of ES-12. Full details can be found in an accompanying comprehensive spreadsheet. Additional investigation and analysis regarding methane reduction opportunities in oil and gas operations should be conducted to refine and improve this analysis in order to determine GHG reductions, costs or savings, and feasibility associated with reducing methane emissions in oil and gas operations.

The oil and gas participants on the TWG do not agree that the analysis conducted is accurate and reflects correct potential reductions or costs.

Estimated GHG Savings and Costs Per Ton:

#	Policy	Scenario	Reductions (MMTCO2e)			NPV (2007–2020) $ Millions	Cost-Effective-ness $/tCO2
			2012	2020	Cumulative Reductions (2007-2020)		
ES-12	Methane reductions in oil and gas operations through BMPs and PROs	Reduce overall CO2e by ~20% over 2007-2020	2.7	3.4	35.3	-$360.4	-$105

ES-12 Initial Analysis: Summary of Results

Analysis conducted by Dr. Lorna Greening	Reductions (MMTCO2e)		Cumulative Reductions 2007-2020	NPV (2007-2020) $Millions	Cost-Effectiveness $/tCO2e
	2012	2020			
Distribution					
High with low reduction scenario	0.12	0.14	1.60	-$20.40	-$142.07
Low with high reduction scenario	0.13	0.14	1.64	-$20.02	-$141.92
Transportation					
High with low reduction scenario	0.36	0.62	5.04	-$31.56	-$50.61
Low with high reduction scenario	0.44	0.49	5.56	-$36.49	-$75.00
Gas Processing					
High with low reduction scenario	0.28	0.35	3.66	-$17.56	-$50.48
Low with high reduction scenario	0.28	0.24	3.42	-$15.77	-$65.51
Production					

High with low reduction scenario	1.78	2.35	23.42	-$272.24	-$116.05
Low with high reduction scenario	2.02	2.52	26.33	-$306.70	-$121.67
Overall					
High with low reduction scenario	2.54	3.46	33.72	-$341.76	-$100.39
Low with high reduction scenario	2.87	3.39	36.95	-$378.98	-$110.35
Midpoint of the above two scenarios	2.71	3.43	35.34	-$360.37	-$105.37

Data Sources, Methods and Assumptions (for quantified actions):

- **Data Sources:** See spreadsheet for details.
- **Quantification Methods:** See spreadsheet for details.
- **Key Assumptions:** See spreadsheet for details.

Key Uncertainties:

- See spreadsheet for details.

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APPENDIX C

US EPA Gas STAR Program Information

1) List of Gas STAR Emissions Reduction Measures

2) Examples of Gas STAR BMPs and PROs
a) Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry
b) Directed Inspection and Maintenance at Gate Stations and Surface Facilities

Natural Gas STAR Recommended Technologies and Practices - Quantification Methods
Table of Contents

Lessons Learned

From Natural Gas STAR Partners

OPTIONS FOR REDUCING METHANE EMISSIONS FROM PNEUMATIC DEVICES IN THE NATURAL GAS INDUSTRY

Executive Summary

Pneumatic devices powered by pressurized natural gas are used widely in the natural gas industry as liquid level controllers, pressure regulators, and valve controllers. Methane emissions from pneumatic devices, which have been estimated at 31 billion cubic feet (Bcf) per year in the production sector, 16 Bcf per year in the processing sector and 14 Bcf per year in the transmission sector, are one of the largest sources of vented methane emissions from the natural gas industry. Reducing these emissions by replacing high-bleed devices with low-bleed devices, retrofitting high-bleed devices, and improving maintenance practices can be profitable.

Natural Gas STAR partners have achieved significant savings and methane emission reductions through replacement, retrofit, and maintenance of high-bleed pneumatics. Partners have found that most retrofit investments pay for themselves in little over a year, and replacements in as little as 6 months. To date, Natural Gas STAR partners have saved 20.4 Bcf by retrofitting or replacing high-bleed with low-bleed pneumatic devices, representing a savings of $61.2 million. Individual savings will vary depending on the design, condition and specific operating conditions of the controller.

Action	Volume of Gas Saved (Mcf/yr)	Value of Gas Saved ($/yr)[1]	Cost of Imlementation ($)	Payback (Months)
Replacement:				
Change to low-bleed device at end of life.	50 to 200	150 to 600	150 to 250[2]	5 to 12
Early-replacement of high-bleed unit.	260	780	1,350	21
Retrofit	230	690	500	9
Maintenance	45 to 260	135 to 780	Negligible to 350	0 to 5

[1]Cost of gas $3.00/Mcf.
[2]Incremental cost of low-bleed over high-bleed equipment.

This is one of a series of Lessons Learned Summaries developed by EPA in cooperation with the natural gas industry on superior applications of Natural Gas STAR Program Best Management Practices (BMPs) and Partner Reported Opportunities (PROs).

Technology Background

The natural gas industry uses a variety of control devices to automatically operate valves and control pressure, flow, temperature or liquid levels. Control devices can be powered by electricity or compressed air, when available and economic. In the vast majority of applications, however, the gas industry uses pneumatic devices that employ energy from pressurized natural gas.

Natural gas powered pneumatic devices perform a variety of functions in all three sectors of the natural gas industry. In the production sector, an estimated 250,000 pneumatic devices are used to control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. In the processing sector, about 13,000 gas pneumatic devices are used for compressor and glycol dehydration control in gas gathering/booster stations and isolation valves in processing plants (process control in gas processing plants is predominantly instrument air).

In the transmission sector, an estimated 90,000 to 130,000 pneumatic devices actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities. Pneumatic devices are also found on meter runs at distribution company gate stations for regulating flow, pressure, and temperature.

As part of normal operation, pneumatic devices release or bleed natural gas to the atmosphere and, consequently, are a major source of methane emissions from the natural gas industry. The actual bleed rate or emissions level largely depends on the design of the device.

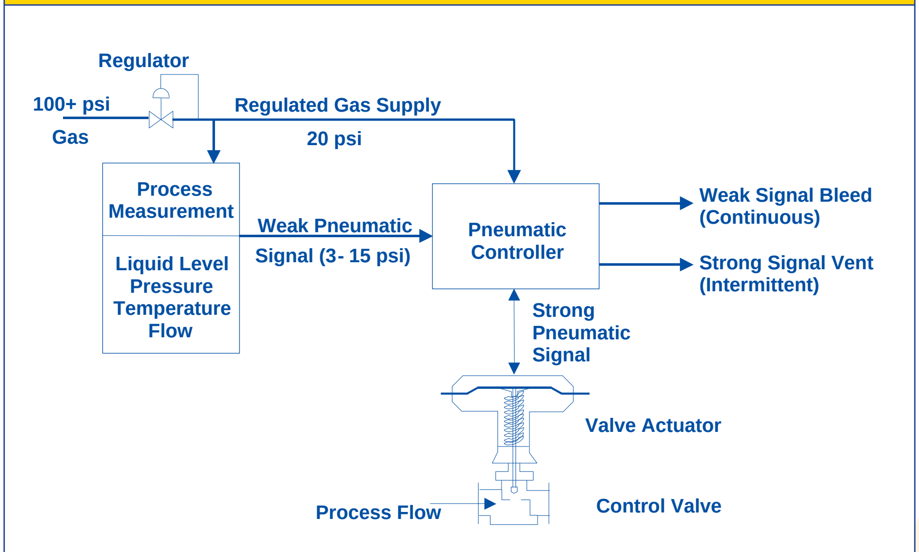
Definition of High-Bleed Pneumatic

Any pneumatic device that bleeds in excess of 6 scfh (over 50 Mcf per year) is considered a high-bleed device by the Natural Gas STAR Program.

Exhibit 1 shows a schematic of a gas pneumatic control system. Clean, dry, pressurized natural gas is regulated to a constant pressure, usually around 20 psig. This gas supply is used both as a signal and a power supply. A small stream is sent to a device that measures a process condition (liquid level, gas pressure, flow, temperature). This device regulates the pressure of this small gas stream (from 3 to 15 psig) in proportion to the process condition. The stream flows to the pneumatic valve controller, where its variable pressure is used to regulate a valve actuator.

To close the valve pictured in Exhibit 1, 20-psig pneumatic gas is directed to the actuator, pushing the diaphragm down against the spring, which, through the valve stem, pushes the valve plug closed. When gas is vented off the actuator, the spring pushes the valve back open. The weak signal continuously vents (bleeds) to the atmosphere. Electro-pneumatic devices use weak electric current instead of the weak gas stream to signal pneumatic valve actuation.

Exhibit 1: Pneumatic Device Schematic



In general, controllers of similar design usually have similar steady-state bleed rates regardless of brand name. Pneumatic devices come in three basic designs:

★ **Continuous** bleed devices are used to modulate flow, liquid level, or pressure and will generally vent gas at a steady rate;

★ **Actuating or intermittent** bleed devices perform snap-acting control and release gas only when they stroke a valve open or closed or as they throttle gas flows; and

★ **Self-contained** devices release gas into the downstream pipeline, not to the atmosphere.

To reduce emissions from pneumatic devices the following options can be pursued, either alone or in combination:

1. Replacement of high-bleed devices with low-bleed devices having similar performance capabilities.
2. Installation of low-bleed retrofit kits on operating devices.
3. Enhanced maintenance, cleaning and tuning, repairing/replacing leaking gaskets, tubing fittings, and seals.

Field experience shows that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted. Exhibit 2 lists the generic options applicable for different controller requirements.

Exhibit 2: Options for Reducing Gas-Bleed Emissions by Controller Type			
Action	**Pneumatic Types**		
	Level Controllers	**Pressure Controllers**	**Positioners/ Transducers**
Replacements High-bleed with low-bleed	X	X	X (electro-pneumatic)
Retrofits Install retrofit kits	X	X	X
Maintenance Lower gas supply pressure/replace springs/re-bench	X	X	X
Repair leaks, clean and tune	X	X	X
Change gain setting	X	X	
Remove unnecessary positioners			X

In general, the bleed rate will also vary with the pneumatic gas supply pressure, actuation frequency, and age or condition of the equipment. Due to the need for precision, controllers that must operate quickly will bleed more gas than slower operating devices. The condition of a pneumatic device is a stronger indicator of emission potential than age; well-maintained pneumatic devices operate efficiently for many years.

Economic and Environmental Benefits

Reducing methane emissions from high-bleed pneumatic devices through the options presented above will yield significant benefits, including:

★ **Financial return from reducing gas-bleed losses.** Using a natural gas price of $3.00 per thousand cubic feet (Mcf), savings from reduced emissions can range from $135 to $780 or more per year per device. In many cases, the cost of implementation is recovered in less than a year.

★ **Increased operational efficiency.** The retrofit or complete replacement of worn units can provide better system-wide performance and reliability and improve monitoring of parameters such as gas flow, pressure, or liquid level.

★ **Lower methane emissions.** Reductions in methane emissions can range from 45 to 260 Mcf per device per year, depending on the device and the specific application.

Decision Process

Operators can determine the gas-bleed reduction option that is best suited to their situation, by following the decision process laid out below. Depending on the types of devices that are being considered, one or more options for reducing pneumatic gas bleed may be appropriate.

Five Steps for Reducing Methane Emissions from Pneumatic Devices:

1. Locate and describe the high-bleed devices;
2. Establish the technical feasibility and costs of alternatives;
3. Estimate the savings;
4. Evaluate the economics; and
5. Develop an implementation plan.

Step 1: Locate and describe the high-bleed devices. Partners should first identify the high-bleed devices that are candidates for replacement, retrofit, or repair. The identification and description process can occur during normal maintenance or during a system-wide or facility-specific pneumatics survey. For each pneumatic device, record the location, function, make and model, condition, age, estimated remaining useful life, and bleed rate characteristics (volume and whether intermittent or continuous).

The pneumatic device's bleed rate can be determined through direct measurement or from data provided by the manufacturer. Direct measurement might include bagging studies at selected instruments, high-volume sampler measurements (see "Directed Inspection and Maintenance at Compressor Stations" Lessons Learned) or the operator's standard leak measurement approach. Operators will find it unnecessary to measure bleed rates at each device. In most cases, sample measurements of a few devices are sufficient. Experience suggests that manufacturers' bleed rates are understated, so measurement data should be used when it can be acquired.

Appendix A lists brand, model, and gas bleed information—as provided by manufacturers—for various pneumatic devices. This is not an exhaustive list, but it covers the most commonly used devices. Where available, actual field data on bleed rates are included.

Step 2: Establish the technical feasibility and costs of alternatives. Nearly all high-bleed pneumatic devices can be replaced or retrofitted with lower-bleed equipment. Consult your pneumatic device vendor or an instrumentation specialist

Some high-bleed devices, however, should not be replaced with low-bleed devices. Control of very large valves that require fast and/or precise response to process changes often require high-bleed controllers. These are found most frequently on large compressor discharge and bypass pressure controllers. EPA recommends contacting vendors for new fast-acting devices with lower bleed rates.

for availability, specifications and costs of suitable devices. Low-bleed devices can be requested by specifying bleed rates less than 6 standard cubic feet per hour (scfh). It is important to note that not all manufacturers report bleed rates in the same manner, and companies should exercise caution when making purchases of low-bleed devices.

Appendix B lists cost data for many low-bleed pneumatic devices and summarizes the compatibility of retrofit kits with various controllers. This is not an exhaustive list, but it covers the most commonly used devices.

Maintenance of pneumatics is a cost-effective method for reducing emissions. All companies should consider maintenance as an important part of their implementation plan. Cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals, can save 5 to 10 scfh per device. Tuning to operate over a broader range of proportional band often reduces bleed rates by as much as 10 scfh. Eliminating unnecessary valve positioners can save up to 18 scfh per device.

Step 3: Estimate the savings. Determine the quantity of gas that can be saved with a low-bleed controller, using field measurement of the high-bleed controller and a similar low-bleed device in service. If these actual bleed rates are not available, use bleed specifications provided by manufacturers.

Gas savings can be monetized to annual savings using $3.00 per Mcf and multiplying bleed reduction, typically specified in scfh, by 8,670 hours per year.

Gas Savings = (High-bleed, scfh) — (Low-bleed, scfh)

Annual Gas Savings = Gas Savings (scfh) * 8,760 hrs/yr * 1 Mcf/1000scf * $3.00/Mcf

Step 4: Evaluate the economics. The cost-effectiveness of replacement, retrofit, or maintenance of high-bleed pneumatic devices can be evaluated using straightforward economic analysis. A cost-benefit analysis for replacement or retrofit is appropriate unless high-bleed characteristics are required for operational reasons.

Exhibit 3 illustrates a cost-benefit analysis for replacement of a high-bleed liquid level controller. Cash flow over a five-year period is analyzed by showing the magnitude and timing of costs (shown in parenthesis) and benefits. In this example, a $380 initial investment buys a level controller that saves

Exhibit 3: Cost-Effectiveness Calculation for Replacement						
Type of Costs	**Year 0**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Implementation Costs, $ (Capital Costs)[1]	(380)					
Annual Savings, $ (New vs. Old)[2]		498	498	498	498	498
Maintenance Costs, $ (New Controller)[3]		(24)	(24)	(24)	(24)	(24)
Avoided Maintenance, $ (Replaced Controller)[3]		50	50	50	50	50
Net Benefit	(380)	524	524	524	524	524
NPV[4] = $1,606 ROI = 138%						

Notes:
[1] Quoted cost of a Fisher 2680 device. See Appendix B.
[2] Annual savings per device calculated as the change in bleed rate of 19 scfh x 8,760 hrs/yr = 167 Mcf/year at $3/Mcf.
[3] Maintenance costs are estimated.
[4] Net Present Value (NPV) based on 10% discount rate for 5 years.

19 scfh of gas. At $3.00 per Mcf, the low-bleed device saves $498 per year. Annual maintenance costs for the new and old controllers are shown. The maintenance cost for the older high-bleed controller is shown as a benefit because it is an avoided cost. Net present value (NPV) is equal to the benefits minus the costs accrued over five years and discounted by 10 percent each year. Return on investment (ROI) is the discount rate at which the NPV generated by the investment equals zero.

Exhibit 4 illustrates the range of savings offered by proven methods for reducing gas bleed emissions. For simplicity, it is assumed that the cost of maintenance of the pneumatic device will be the same before and after the replacement, retrofit, or enhanced maintenance activity.

As seen in Exhibit 4, sometimes more than one option to reduce gas bleed may be appropriate and cost-effective for a given application. For the listed options, please note that the payback period with respect to implementation cost can range from less than one month to two years.

Exhibit 4: Economic Benefits of Reducing Pneumatic Device Emissions					
Action	**Cost[1] ($)**	**Bleed Rate Reductions[2] (Mcf/yr/device)**	**Annual Savings[3] ($/year)**	**Payback Period (Months)**	**Return on Investment[4] (Percent)**
Replacement					
Level Controllers					
High-bleed to low-bleed	380	166	498	9	31
Pressure Controllers					
High-bleed to low-bleed	1,340	228	684	24	42
Airset metal to soft-seat	77	219	657	1.4	>800
Retrofit					
Level Controllers					
Mizer	500	219	657	9	131
Large orifice to small	30	184	552	<1	>1,800
Large nozzle to small	140	131	393	4	>250
Pressure Controllers					
Large orifice to small	30	184	552	<1	>1,800
Maintenance					
All types					
Reduce supply pressure	153	175	525	4	>300
Repair leaks, retune	23	44	132	2	>500
Level Controllers					
Change gain setting	0	88	264	immediate	---
Positioners					
Remove unnecessary	0	158	474	immediate	---

[1]Implementation costs represent average costs for Fisher brand pneumatic instruments installed.
[2]Bleed rate reduction = change in bleed rate scf/hr x 8,760 hr/yr.
[3]Savings based on $3.00/Mcf cost of gas.
[4]Return on investment (ROI) calculated over 5 years.

Exhibit 5: Case Studies on Retrofits To Reduce Gas Leaks at Natural Gas STAR Partner Sites					
Study	**Implementation Costs ($)**	**Emissions Reductions (Mcf/yr)**	**Annual Savings ($/yr)**	**Payback (Months)**	**Return on Investment (%)**
Company 1:					
Platform 1	6,405	2,286	6,858	11	104
Platform 2	9,900	3,592	10,776	11	106
Retrofit Liquid-level controllers	3,885	1,717	5,151	9	131
Company 2:					
Per device	500	219	$657	9	129

The case studies in Exhibit 5 above present analyses performed and savings achieved by two Natural Gas STAR partners who installed retrofit kits at gas production facilities.

Step 5: Develop an implementation plan. After identifying the pneumatic devices that can be profitably replaced, retrofitted or maintained, devise a systematic plan for implementing the required changes. This can include modifying the current inspection and maintenance schedule and prioritizing replacement or retrofits. It may be most cost-effective to replace all those devices that meet the technical and economic criteria of your analysis at one time to minimize labor costs and disruption of operation.

Where a pneumatic device is at the end of its useful life and is scheduled for replacement, it should be replaced with a low-bleed model instead of a new high-bleed device whenever possible.

Other Technologies

Instrument air, nitrogen gas, electric valve controllers, and mechanical control systems are some of the alternatives to gas powered pneumatics implemented by partners.

★ **Instrument Air.** These systems substitute compressed, dried air in place of natural gas in pneumatic devices, and thus eliminate methane emissions entirely. Instrument air systems are typically installed at facilities where there is a high concentration of pneumatic control valves and full-time operator presence (for example, most gas processing plants use instrument air for pneumatic devices). The major costs associated with instrument air systems are capital and energy. Instrument air systems are powered by electric compressors, and require the installation of dehydrators and volume tanks to filter, dry and store the air for instrumentation use. Generally, partners have found that cost-effective implementation of instrument air systems is limited to field sites with available utility or self-generated electrical power. The Lessons Learned study, "Covert Gas Pneumatic Controls to Instrument Air," provides a detailed description of the technical and economic decision process required to evaluate conversion from gas pneumatic devices to instrument air.

★ **Nitrogen Gas.** Unlike instrument air systems that require capital expenditures and electric power, these systems only require the installation of a cryogenic liquid nitrogen cylinder, that is replaced periodically, and a liquid nitrogen vaporizer. The system uses a pressure regulator to control the expansion of the nitrogen gas (i.e., the gas pressure) as it enters the control system. The primary disadvantage of these systems stems from the cost of liquid nitrogen and the potential safety hazard associated with using cryogenic liquids.

★ **Electric Valve Controllers.** Due to advances in technology, the use of electronic control instrumentation is increasing. These systems use small electrical motors to operate valves and therefore do not bleed methane into the atmosphere. While they are reliant on a constant supply of electricity, and have high associated operating costs, they have the advantage of not requiring the utilization of natural gas or a compressor to operate.

★ **Mechanical Control Systems.** These devices have been widely used in the natural gas and petroleum industry. They operate using a combination of springs, levers, flow channels and hand wheels. While they are simple in design and require no natural gas or power supply to operate, their application is limited due to the need for the control valve to be in close proximity to the process measurement. Also, these systems are unable to handle large flow fluctuations and lack the sensitivity of pneumatic systems.

Each of these options has specific advantages and disadvantages. Where Natural Gas STAR partners do install these systems as replacements to gas powered pneumatic devices, they should report the resulting emissions reductions and recognize the savings.

One Partner's Experience

Marathon Oil Company surveyed 158 pneumatic control devices at 50 production sites using the Hi-Flow Sampler to measure emissions. Half of these controllers were identified as non-bleed devices (e.g. weighted dump valves, spring operated regulators, enclosed capillary temperature controllers, non-bleed pressure switches). High-bleed devices accounted for 35 of 67 level controllers, 5 of 76 pressure controllers, and 1 of 15 temperature controllers. Measured gas emissions were 583 scfh total; 86 percent of emissions came from level controllers, with leaks up to 48 scfh, and averaging 7.6 scfh. Marathon concluded that "control devices with higher emissions can be identified qualitatively by sound prior to leak measurement, making it unnecessary to quantitatively measure methane emissions using technologically advanced equipment."

One Partner's Experience

Union Pacific Resources replaced 70 high-bleed pneumatic devices with low-bleed pneumatic devices and retrofitted 330 high-bleed pneumatic devices. As a result, this partner has estimated a total reduction of methane emissions of 49,600 Mcf per year. Assuming a gas price of $3 per Mcf, the savings corresponds to $148,800. The costs of replacing and retrofitting all the devices, including materials and labor, was $118,500, resulting in a payback period of less than one year.

Lessons Learned

Natural Gas STAR partners offer the following Lessons Learned:

- ★ Hear it; feel it; replace it. Where emissions can be heard or felt, this is a sign that emissions are significant enough to warrant corrective action.
- ★ Control valve cycle frequency is another indicator of excessive emissions. When devices cycle more than once per minute, they can be replaced or retrofitted profitably.
- ★ Manufacturer bleed rate specifications are not necessarily what users will experience. Actual bleed rates will generally exceed manufacturer's specifications because of operating conditions different from manufacturer's assumptions, installation settings and maintenance.
- ★ Combine equipment retrofits or replacements with improved maintenance activities. Do not overlook simple solutions such as replacing tubes and fittings or rearranging controllers.
- ★ The smaller orifices in low-bleed devices and retrofit kits can be subject to clogging from debris in corroded pipes. Therefore, pneumatic supply gas piping and tubing should be flushed out before retrofitting with smaller orifice devices, and gas filters should be well maintained.

- ★ When replacing pneumatic control systems powered by pressurized natural gas with instrument air or other systems, do not forget to account for the savings from the resulting methane emission reductions.
- ★ Include methane emission reductions from pneumatics in annual reports submitted as part of the Natural Gas STAR Program.

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Appendix A

The following chart contains manufacturer-reported bleed rates. Actual bleed rates have been included whenever possible. Discrepancies occur due to a variety of reasons, including:

★ Maintenance.

★ Operating conditions.

★ Manufacturer vs. operating assumptions.

It is important to note that manufacturer information has not been verified by any third party and there may be large differences between manufacturer-reported bleed rates and those found during operations. Until a full set of information is available, companies should be careful to compare bleed rates in standard units (CFH) when comparing manufacturers and models. During this study we found that manufacturers reported information in a wide range of different units and operating assumptions.

Gas Bleed Rate for Various Pneumatic Devices			
Controller Model	Type	Consumption Rate (CFH)	
		Manufacturer Data	Field Data (where available)
High-Bleed Pneumatic Devices			
**Fisher 4100 Series	Pressure controller (large orifice)	35	
**Fisher 2500 Series	Liquid-level controllers (P.B. in mid range)	10-34	44-72
*Invalco AE-155	Liquid-level controller		44-63
*Moore Products – Model 750P	Positioner	42	
*Invalco CT Series	Liquid-level controllers	40	34-87
**Fisher 4150/4160K	Pressure controller (P.B. 0 or 10)	2.5-29	
**Fisher 546	Transducer	21	
**Fisher 3620J	Electro-pneumatic positioner	18.2	
Foxboro 43AP	Pressure controller	18	
**Fisher 3582i	Electro-pneumatic positioner	17.2	
**Fisher 4100 Series	Pressure controller (small orifice)	15	
**Fisher DVC 6000	Electro-pneumatic positioner	14	
**Fisher 846	Transducer	12	
**Fisher 4160	Pressure controller (P.B. 0.5)	10-34	
**Fisher 2506	Receiver controller (P.B.0.5)	10	
**Fisher DVC 5000	Electro-pneumatic positioner	10	
**Masoneilan 4700E	Positioners	9	
**Fisher 3661	Electro-pneumatic positioner	8.8	

**Fisher 646	Transducer	7.8	
**Fisher 3660	Pneumatic positioner	6	
**ITT Barton 335P	Pressure controller	6	
*Ametek Series 40	Pressure controllers	6	
Low or No-Bleed Pneumatic Devices			
**Masoneilan SV	Positioners	4	
**Fisher 4195 Series	Pressure controllers	3.5	
**ITT Barton 273A	Pressure transmitter	3	
**ITT Barton 274A	Pressure transmitter	3	
**ITT Barton 284B	Pressure transmitter	3	
**ITT Barton 285B	Pressure transmitter	3	
**Bristol Babcock Series 5457-70F	Transmitter	3	
**Bristol Babcock Series 5453-Model 624-II	Liquid-level controllers	3	
**Bristol Babcock Series 5453-Model 10F	Pressure controllers	3	
**Bristol Babcock Series 5455 Model 624-III	Pressure controllers	3	
**ITT Barton 358	Pressure controller	1.8	
**ITT Barton 359	Pressure controller 1.8	1.8	
**Fisher 3610J	Pneumatic positioner	16	
**Bristol Babcock Series 502 A/D	Recording pneumatic controllers	<6	
**Fisher 4660	High-low pressure pilot	<5	
**Bristol Babcock Series 9110-00A	Transducers	0.42	
Fisher 2100 Series	Liquid-level controllers	1	
**Fisher 2680	Liquid level controllers	<1	
*Norriseal 1001 (A) (Snap)	Liquid-level controller	0.2	0.2
*Norriseal 1001 (A) ('Envirosave')	Liquid-level controller	0	0
*Norriseal 1001 (A) (Throttle)	Liquid-level controller	0.007	0.007
**Becker VRP-B-CH	Double-acting pilot pressure control system (replaces controllers and positioners)	0-10	
**Becker HPP-5	Pneumatic positioner (Double Acting)	0-10	
**Becker EFP-2.0	Electro-pneumatic positioner	0	
**Becker VRP-SB	Single-acting pilot pressure control system (replaces controllers and positioners)	0	

**Becker VRP-SB GAP Controller	Replaces pneumatic "gap" type controllers	0	
**Becker VRP-SB-PID Controller	Single-acting pilot pressure control system specifically designed for power plant type feeds (replaces controllers and positioners)	0	
**Becker VRP-SB-CH	Single-acting pilot pressure control system (replaces controllers and positioners)	0	
**Becker HPP-SB	Pneumatic positioner (Single Acting)	0	
Actuator Model	**Size**	**Manufacturer Data**	**Field Data**
*Shafer RV-Series	33" x 32"	1,084	
Rotary Vane Valve	36" x 26"	768	
Actuators	26" x 22"	469	
	25" x 16"	323	
	20" x 16"	201	
	16.5" x 16"	128	
	14.5" x 14"	86	
	12.5" x 12"	49	
	12" x 9"	22	
	11" x 10"	32	
	9" x 7"	12	
	8" x 6.5"	8	
	6.5" x 3.5"	6	
	5" x 3"	6	
Actuator Model	**Size**	**Number of Snap-acting Strokes per CF**	**Number of Throttling Strokes per CF**
**Fisher Valve Actuators	20	21	39
**Fisher Valve Actuators	30	12	22
**Fisher Valve Actuators	34/40	6	10
**Fisher Valve Actuators	45/50	3	5
**Fisher Valve Actuators	46/50	2	3

* Last updated in 1996.

** Last updated in 2001.

Appendix B

Controllers Compatible with MIZER Retrofits	
Type	**Brand/model Number**
Liquid-level controllers	C.E. Invalco – 215, 402, AE-155
	Norriseal – 1001, 1001A
Pressure controllers	Norriseal - 4300

Suggested Retail Prices for Various Brand Low-Bleed Pneumatic Devices (Estimates Based on Best Information Available at Time of Publication)	
Brand/Model	**Price per Device**
**ITT Barton 335P (pressure controller)	$920
**ITT Barton 273A (pressure transmitter)	$1,010
**ITT Barton 274A (pressure transmitter)	$1,385
**ITT Barton 284B (pressure transmitter)	$1,605
**ITT Barton 285B (pressure transmitter)	$1,990
**ITT Barton 340E (recording pressure controller)	$1,400
**ITT Barton 338E (recorder controller)	$2,800
**Ametek Series 40 (pressure controllers)	$1,100 (average cost)
**Becker VRP-B-CH	$1,575.00
**Becker HPP-5	$1,675.00
**Becker VRP-SB	$1,575.00-$2,000.00
**Becker VRP-SB-CH-PID	$2,075.00
**Becker VRP-SB-CH	$1,575.00
**Becker HPP-SB	$1,675.00
**Mizer Retrofit Kits	$400-$600
**Fisher 67AFR (airset regulators)	$80
**Fisher 2680 (liquid-level controllers)	$380
**Fisher 4195 (pressure controllers)	$1,340
**Bristol Babcock Series 9110-00A (transducers)	$1,535-$1,550
**Bristol Babcock Series 5453 (controllers)	$1,540
**Bristol Babcock Series 5453 40 G (temperature controllers)	$3,500
**Bristol Babcock Series 5457-624 II (controllers)	$3,140
**Bristol Babcock Series 502 A/D (recording controllers)	$3,000
**Bristol Babcock Series 5455-624 III (pressure controllers)	$1,135
**Bristol Babcock Series 5453-624 II (liquid level controllers)	$2,345
**Bristol Babcock Series 5453-10F (pressure controllers)	$1,440

* Last updated in 1996.

** Last updated in 2001.

United States
Environmental Protection Agency
Air and Radiation (6202J)
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Lessons Learned

From Natural Gas STAR Partners

DIRECTED INSPECTION AND MAINTENANCE AT GATE STATIONS AND SURFACE FACILITIES

Executive Summary

In 2001, fugitive methane emissions from gate stations and surface facilities in the United States totaled about 27 million cubic feet (MMcf) from leaking meters and regulating equipment. Implementing a directed inspection and maintenance (DI&M) program is a proven, cost-effective way to detect, measure, prioritize, and repair equipment leaks to reduce methane emissions.

A DI&M program begins with a baseline survey to identify and quantify leaks. Repairs that are cost-effective to fix are then made to the leaking components. Subsequent surveys are based on data from previous surveys, allowing operators to concentrate on the components that are most likely to leak and are profitable to repair. This Lessons Learned study focuses on maximizing the savings that can be achieved by implementing DI&M programs at gate stations and surface facilities.

Natural Gas STAR distribution partners have reported significant savings and methane emissions reductions by implementing DI&M. Based on partner data, implementing DI&M at gate stations and surface facilities can result in gas savings worth up to $1,800 per year, at a cost of between $20 and $1,200.

Leak Source	Annual Volume of Gas Gas Lost(Mcf/site)	Method for Reducing Loss	Value of Gas Saved[1] per site	Total Cost to Find and Fix Leaks	Annual Partner Savings
Gate Station and Surface Facility Equipment	0 to 600 (typical estimates for leaking facilities is 30 to 200)	Locating and repairing leaks.	Up to $1,800	$20 to more than $1,200 (varies depending on facility size and types of repairs)	$50 to more than $1,000 (varies depending on survey costs, leak rates, number of sites)

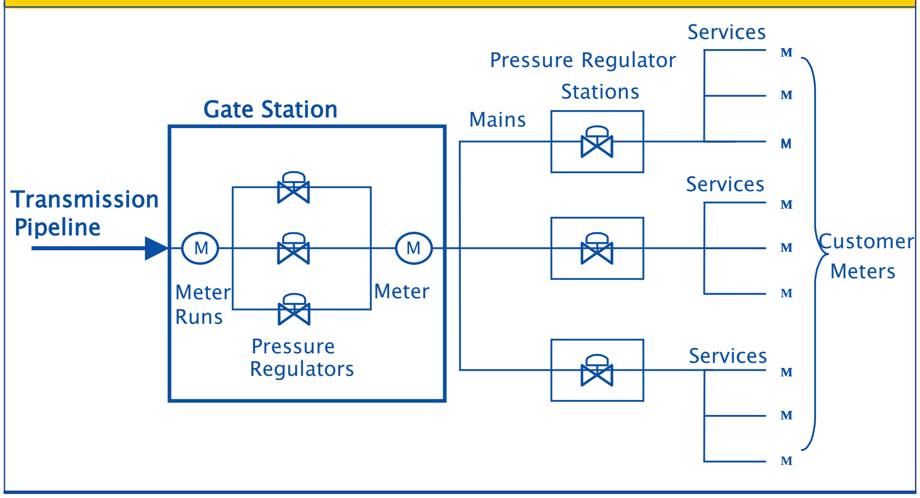
[1]Gas valued at $3 per Mcf.

This is one of a series of Lessons Learned Summaries developed by EPA in cooperation with the natural gas industry on superior applications of Natural Gas STAR Program Best Management Practices (BMPs) and Partner Reported Opportunities (PROs).

Introduction

Gate stations (or 'city gates') are metering and pressure regulating facilities located at the custody transfer points where natural gas is delivered from transmission pipelines into the high-pressure lines of a local distribution company. Gate stations typically contain metering runs as well as pressure regulators, which reduce the transmission line pressure from several hundred pounds per square inch gauge (psig) to a suitable pressure for the distribution system (usually less than 300 psig). Other surface facilities within a distribution system include heaters to replace the heat lost from gas expansion, and downstream pressure regulators, which further reduce gas pressure so that gas can be delivered safely to customers. Exhibit 1 is a schematic illustration of a gas distribution system showing a gate station and pressure regulating facilities.

Exhibit 1: Distribution System Schematic Showing Gate Station and Pressure Regulators



Gate stations and surface facilities contain equipment components such as pipes, valves, flanges, fittings, open-ended lines, meters, and pneumatic controllers to monitor and control gas flow. Over time, these components can develop leaks in response to temperature fluctuations, pressure, corrosion and wear. In general, the size of the facility and the facility leak rate correspond to the inlet or upstream gas pressure; the higher the inlet pressure, the larger the gate station and the greater the number of equipment components that may develop leaks.

Technology Background

DI&M is a cost-effective way to reduce natural gas losses from equipment leaks. A DI&M program begins with a comprehensive baseline survey of all the gate stations and surface facilities in the distribution system. Operators identify, measure, and evaluate all leaking components and use the results to direct subsequent inspection and maintenance efforts.

The following sections describe various leak screening and measurement techniques that can be cost-effective at gate stations and pressure regulating facilities. The appropriateness of the various screening and measurement techniques will depend upon the configuration and operating characteristics of individual distribution system facilities.

Leak Screening Techniques

Leak screening in a DI&M program may include all components in a comprehensive baseline survey, or may be focused only on the components that are likely to develop significant leaks. Several leak screening techniques can be used:

- ★ **Soap Bubble Screening** is a fast, easy, and very low-cost leak screening technique. Soap bubble screening involves spraying a soap solution on small, accessible components such as threaded connections. Soaping is effective for locating loose fittings and connections, which can be tightened on the spot to fix the leak, and for quickly checking the tightness of a repair. Operators can screen about 100 components per hour by soaping.
- ★ **Electronic Screening** using small hand-held gas detectors or "sniffing" devices provides another fast and convenient way to detect accessible leaks. Electronic gas detectors are equipped with catalytic oxidation and thermal conductivity sensors designed to detect the presence of specific gases. Electronic gas detectors can be used on larger openings that cannot be screened by soaping. Electronic screening is not as fast as soap screening (averaging 50 components per hour), and pinpointing leaks can be difficult in areas with high ambient concentrations of hydrocarbon gases.
- ★ **Organic Vapor Analyzers (OVAs) and Toxic Vapor Analyzers (TVAs)** are portable hydrocarbon detectors that can also be used to identify leaks. An OVA is a flame ionization detector (FID), which measures the concentration of organic vapors over a range of 9 to 10,000 parts per million (ppm). A TVA combines both an FID and a photoionization detector (PID) and can measure organic vapors at concentrations exceeding 10,000 ppm. TVAs and OVAs measure the concentration of methane in the area around a leak.

  Screening is accomplished by placing a probe inlet at an opening where leakage can occur. Concentration measurements are observed as the probe is slowly moved along the interface or opening, until a maximum concentration reading is obtained. The maximum concentration is recorded as the leak screening value. Screening with TVAs is somewhat slow—approximately 40 components per hour—and the instruments require frequent calibration.

★ **Acoustic Leak Detection** uses portable acoustic screening devices designed to detect the acoustic signal that results when pressurized gas escapes through an orifice. As gas moves from a high-pressure to a low-pressure environment across a leak opening, turbulent flow produces an acoustic signal, which is detected by a hand-held sensor or probe, and read as intensity increments on a meter. Although acoustic detectors do not measure leak rates, they provide a relative indication of leak size—a high intensity or "loud" signal corresponds to a greater leak rate. Acoustic screening devices are designed to detect either high frequency or low frequency signals.

Exhibit 2. Acoustic Leak Detection

Source: Physical Acoustics Corp.

High Frequency Acoustic Detection is best applied in noisy environments where the leaking components are accessible to a handheld sensor. As shown in Exhibit 2, an acoustic sensor is placed directly on the equipment orifice to detect the signal. Alternatively, *Ultrasound Leak Detection* is an acoustic screening method that detects airborne ultrasonic signals in the frequency range of 20 kHz to 100 kHz. Ultrasound detectors are equipped with a hand-held acoustic probe or scanner that is aimed at a potential leak source from a distance up to 100 feet. Leaks are pinpointed by listening for an increase in sound intensity through headphones. Ultrasound detectors can be sensitive to background noise, although most detectors typically provide frequency tuning capabilities so that the probe can be tuned to a specific leak in a noisy environment.

Leak Measurement Techniques

An essential component of a DI&M program is measurement of the mass emissions rate or leak volume of identified leaks, so that manpower and resources are allocated only to the significant leaks that are cost-effective to repair. Four leak measurement techniques can be used: conversion of TVA and OVA screening concentrations using general correlation equations; bagging techniques; high volume samplers; and rotameters.

Data available for total fugitive emissions rates from gate stations and surface facilities indicates that the leak rate for many components is relatively small. For most gate stations, DI&M will only be cost-effective using the lowest cost measurement technique, which is likely to be conversion of TVA/OVA screening values using EPA correlation equations and TVA or OVA instruments that may already be at hand.

★ **OVAs and TVAs** can be used to estimate mass leak rate. The screening concentration detected at a leak opening is not a direct measurement of the mass emissions of the leak. However, the screening concentration in ppm is converted to a mass emissions rate by using EPA correlation equations. The EPA correlation equations can be used to estimate emissions rates for the entire range of screening concentrations, from the detection limit of the instrument to the “pegged” screening concentration, which represents the upper limit of the instrument. If the upper measurement limit of the TVA is 10,000 ppm, a dilution probe can be used to detect screening concentrations up to 100,000 ppm.

OVAs and TVAs must be calibrated using a reference gas containing a known compound at a known concentration. Methane in air is a frequently used reference compound. The calibration process also determines a response factor for the instrument, which is used to correct the observed screening concentration to match the actual concentration of the leaking compound. For example, a response factor of “one” means that the screening concentration read by the TVA equals the actual concentration at the leak.

Screening concentrations detected for individual components are corrected using the response factor (if necessary) and are entered into EPA correlation equations to extrapolate a leak rate measurement for the component. Exhibit 3 lists the EPA correlation equations for equipment components at oil and gas industry facilities.

Exhibit 3: U.S. EPA Leak Rate/Screening Value Correlation Equations for Equipment Components in the Oil and Gas Industry

Equipment Component	EPA Leak Rate/Screening Value Correlation (kg/hr/source)	Leak Rate Correlation (kg/hr) for "Pegged" Screening Value >10,000 ppm	Leak Rate Correlation (kg/hr) for "Pegged" Screening Value >100,000 ppm
Valves	$2.29E\text{-}06 \times (SV)^{0.746}$	0.064	0.140
Pump Seals	$5.03E\text{-}05 \times (SV)^{0.610}$	0.074	0.160
Connectors	$1.53E\text{-}06 \times (SV)^{0.735}$	0.028	0.030
Flanges	$4.61E\text{-}06 \times (SV)^{0.703}$	0.085	0.084
Open-Ended Lines	$2.20E\text{-}06 \times (SV)^{0.704}$	0.030	0.079
Other Components (instruments, pressure relief, vents, all others)	$1.36E\text{-}05 \times (SV)^{0.589}$	0.073	0.110

The correlations presented are revised petroleum industry correlations. Correlations predict total organic compound emissions rates.

Correlation factors for methane: 1kg methane = 51.92 scf; 1kg/hr = 1.246 Mcfd.

Source: U.S. EPA, 1995, Protocol for Equipment Leak Emission Estimates.

Exhibit 4 provides a table based on the above EPA correlation equations for TVAs and OVAs. This can be used to estimate mass leak rate from the screening concentrations detected at leaking components at gate stations and surface facilities.

Exhibit 4. Example Screening Concentration/Leak Rate Correlations

Screening Concentration (ppmv)	Estimated Mass Leak Rate (Mcf/yr)					
	Valves	Pump Seals	Connectors	Flanges	Open-Ended Lines	Other[1]
1	0.001	0.023	0.001	0.002	0.001	0.006
10	0.006	0.093	0.004	0.011	0.005	0.024
100	0.032	0.380	0.021	0.053	0.026	0.093
1,000	0.180	1.547	0.112	0.269	0.130	0.362
10,000	1.004	6.301	0.606	1.360	0.655	1.404
100,000	5.593	25.669	3.293	6.864	3.313	5.450
Screening value pegged at >10,000	29.109	33.657	12.735	38.660	13.645	33.203
Screening value pegged at >100,000	63.676	72.773	13.645	38.206	35.931	50.031

[1]"Other" equipment components include: instruments, loading arms, pressure relief valves, stuffing boxes, and vents. Apply to any equipment component other than connectors, flanges, open-ended lines, pumps, or valves.

Source: U.S. EPA, 1995, Protocol for Equipment Leak Emission Estimates.

- ★ **Bagging Techniques** are commonly used to measure mass emissions from equipment leaks. The leaking component or leak opening is enclosed in a “bag” or tent. An inert carrier gas such as nitrogen is conveyed through the bag at a known flow rate. Once the carrier gas attains equilibrium, a gas sample is collected from the bag and the methane concentration of the sample is measured. The mass emissions rate is calculated from the measured methane concentration of the bag sample and the flow rate of the carrier gas. Leak rate measurement using bagging techniques is accurate (within ± 10 to 15 percent) but, slow and labor intensive (only two or three samples per hour). Bagging techniques can be expensive due to the labor involved to perform the measurement, as well as the cost for sample analysis.
- ★ **High Volume Samplers** capture all of the emissions from a leaking component to accurately quantify leak emissions rates. Leak emissions, plus a large volume sample of the air around the leaking component, are pulled into the instrument through a vacuum sampling hose. Sample measurements are corrected for the ambient hydrocarbon concentration, and mass leak rate is calculated by multiplying the flow rate of the measured sample by the difference between the ambient gas concentration and the gas concentration in the measured sample. High volume samplers measure leak rates up to 8 cubic feet per minute (scfm), a rate equivalent to 11.5 thousand cubic feet (Mcf) per day. Two operators can measure 30 components per hour using a high volume sampler, compared with two to three measurements per hour using bagging techniques. High volume samplers can cost approximately $10,000 to purchase. Alternatively, contractors can provide leak measurement services at rate that ranges from $1.00 to more than $2.50 per component measured.
- ★ **Rotameters** and other flow meters are used to measure extremely large leaks that would overwhelm other instruments. Flow meters typically channel gas flow from a leak source through a calibrated tube. The flow lifts a "float bob" within the tube, indicating the leak rate. Because rotameters are bulky, these instruments work best for open-ended lines and similar components, where the entire flow can be channeled through the meter. Rotameters and other flow metering devices can supplement measurements made using bagging or high volume samplers.

Decision Process

A DI&M program can be implemented in four steps: (1) conduct a baseline survey; (2) record the results and identify candidates for cost-effective repair; (3) analyze the data, make the repairs, and estimate methane savings; and (4) develop a survey plan for future inspections and follow-up monitoring of leak-prone equipment.

Decision Steps for DI&M

1. Conduct baseline survey.
2. Record results and identify candidates for repair.
3. Analyze data and estimate savings.
4. Develop a survey plan for future DI&M.

Step 1: Conduct Baseline Survey. A DI&M program typically begins with baseline screening to identify leaking components. For each leaking component the mass leak rate is estimated using one of the techniques described above. In the distribution sector, the emissions from leaking equipment components at gate stations and surface facilities may be one or more orders of magnitude less than emissions from leaks at compressor stations. For DI&M to be cost-effective at gate stations and surface facilities, the baseline survey costs must be minimal.

Some distribution sector partners elect to conduct leak screening only, using very low cost and rapid leak detection techniques, which are incorporated into ongoing maintenance operations. In these cases, all of the leaks that are identified are repaired. A baseline survey that focuses only on leak screening is substantially less expensive. However, leak screening alone does not quantify leak rate or potential gas savings, each of which is critical information needed to make cost-effective repair decisions in cases where partners do not have the resources to repair all leaks.

Step 2: Record Results and Identify Candidates for Repair. Leak measurements collected in Step 1 must be recorded to pinpoint the leaking components that are cost-effective to repair.

As leaks are identified and measured, operators should record the baseline leak data so that future surveys can focus on the most significant leaking components. The results of the DI&M survey can be tracked using any convenient method or format. The information that operators may choose to collect includes: (1) an identifier for each leaking component; (2) the component type (e.g., gate valve); (3) the measured leak rate; (4) the survey date; (5) the estimated annual gas loss; and (6) the estimated repair cost. This information will direct subsequent emissions surveys, prioritize future repairs, and track the methane savings and cost-effectiveness of the DI&M program.

Natural Gas STAR partners report that the most common leaks at gate stations and surface facilities are pinhole leaks and component flaws, loose connections, and loose or worn valve stem seals. High frequency leak locations identified by partners include: orifice plate/fittings, plugs installed on test points, grease fittings on valves, multiple or large diameter meter runs, couplings, valve stem packing, and flanges. The largest leaks are generally located at pressure relief valves, open-ended lines, flanges, gate valves, and gate valve stem packing. Leaks are prioritized by comparing the value of the natural gas lost with the estimated cost in parts, labor, and equipment downtime to fix the leak.

Gate stations and surface facilities vary significantly in size and pressure capacity depending upon the size and complexity of the distribution system. As a result, there can be substantial variation in fugitive methane emissions from such facilities. A 1994 field study sponsored by EPA and the Gas Research Institute (GRI—now GTI, the Gas Technology Institute) used a tracer gas technique to measure total facility methane emissions at 40 gate stations and 55 district pressure regulators. This study found that average annual methane emissions ranged from 1,575 Mcf per year for gate stations with inlet pressures greater than 300 psig to less than 1 Mcf per year for district regulators with inlet pressures less than 40 psig. Average annual facility emissions, based on all 95 sample facilities were 425 Mcf. This study estimated that a large component of total site emissions are contributed by pneumatic controllers, which are designed to bleed gas to the atmosphere.

In 1998, EPA, GRI, and the American Gas Association Pipeline Research Committee International (PRCI) conducted a second study of methane emissions from equipment components at 16 natural gas metering and regulating facilities in transmission and distribution. Four of the facilities studied were distribution system gate stations. This analysis included component counts for each site, and leak screening and measurement of individual component leaks using a high volume sampler. As in the earlier study, pneumatic controllers were found to contribute most of the total site emissions (more than 95 percent). Because pneumatic devices are designed to bleed gas during normal operation, these emissions are not considered leaks. Pneumatic controllers provide a significant opportunity to reduce methane emissions from gate stations and surface facilities, which is the subject of *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air* and *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry.*

Exhibit 5. Average Emissions Factors for Equipment Leaks at Sixteen Metering and Regulating Facilities			
Component	**Emissions Factor (Mcf/yr/component)**	**Total Number Components Screened**	**Average Number Components per Site**
Ball/Plug Valve	0.21	248	18
Control Valve	0.46	17	1
Flange	0.13	525	38
Gate Valve	0.79	146	10
Pneumatic Vent	134.3	40	1
Pressure Relief Valve	4.84	5	1
Connectors	0.11	1280	91
Total		**2,261**	**162**
Source: Indaco Air Quality Services, 1998.			

Exhibit 5 summarizes average component emissions factors obtained during the 1998 field study. Approximately 5 percent of the 2,261 total components screened were found to be leaking.

Exhibit 5 shows that pressure relief valves were found to be the largest leak source, followed by gate valves and control valves. The smallest leaks were found at connectors, flanges, and ball/plug valves. Exhibit 5 indicates that the typical leak to be expected at gate state stations and surface facilities is relatively small, and the number of components to be surveyed at each facility is over 100.

Based on the leak measurements of individual equipment components, the 1998 study determined the average total gas emissions from metering and regulating facilities to be 409 Mcf per year. Excluding the total facility emissions contributed by pneumatic controllers, the average total emissions contributed by equipment leaks was in the range of 20 to 40 Mcf per site, although substantial leaks in the range of 60 to 100 Mcf per year were reported for some of the sites.

The 1998 field study reinforces the point made in Step 1, that a cost-effective DI&M program at gate stations and surface facilities must rely upon very low cost and rapid screening techniques. Otherwise, the cost of finding the leaks might not outweigh the savings gained from fixing the leaks.

Step 3: Analyze Data and Estimate Savings. Cost-effective repair is a critical part of successful DI&M programs because the greatest savings are achieved by targeting only those leaks that are profitable to repair. Some leaks can be fixed on the spot, for example, by simply tightening a valve-stem packing-gland. Other repairs are more complicated and require equipment downtime or new parts. For these repairs, operators may choose to attach identification markers, so that the leaks can be fixed later.

Easy repairs should be done on the spot, as soon as the leaks are found. In all cases, the value of the gas saved should exceed the cost to find and fix the leak. Partners have found that an effective way to analyze baseline survey results is to create a table listing all leaks with their associated repair cost, expected gas savings, and expected life of the repair. Using this information, economic criteria such as payback period can be easily calculated for each leak repair. Partners can then decide which leaking components are economic to repair.

Exhibit 6 provides an example of this type of repair cost analysis, which summarizes the repair costs, total gas savings, and the estimated net savings for the anticipated repairs. The leak and repair data featured in Exhibit 6 are from the 1998 EPA/GRI/PRCI field study, during which leak repairs were evaluated for two of the sixteen facilities included in the study.

Exhibit 6. Example of Repair Costs and Net Savings for Selected Equipment Components

Component Description	Type of Repair	Repair Cost[1] (includes labor & material)	Total Number of Components Fixed at Two Sites	Total Gas Savings (Mcf/yr)	Estimated Net Savings[2] $/yr	Repair Payback Period (Years)
Ball Valve	Re-grease	$13	5	60 Mcf	$115	0.4
Gate Valve	Replace valve stem packing	$3	5	67 Mcf	$36	0.8
Gate Valve	Replace valve stem packing	$3	1	92 Mcf	$243	0.1
Connectors	Tighten Threaded Fittings	$3	4	11 Mcf	$21	0.4
Sr. Daniel Orifice Meter	Tighten Fittings	$33	1	68 Mcf	$171	0.2
Flange[3]	Tighten (estimated)	$ 40	5	99 Mcf	$97	0.7

[1]Average repair costs are in 2002 dollars.

[2]Assumes gas price of $3/Mcf.

[3]Repair cost not reported in original study. Flange repair cost estimated based on similar 1997 data on leak repair cost for "off-compressor" flanges at compressor stations.

Source: Indaco Air Quality Services, Inc., 1998, Trends in Leak Rates at Metering and Regulating Facilities and the Effectiveness of Leak Detection and Repair (LDAR) Programs, Draft Report.

Because of safety concerns, some partners repair all leaks found at gate stations and meter stations. In this case, a DI&M program may be useful for improving the cost-effectiveness of ongoing inspection and maintenance operations by prioritizing repairs—the major leaks are identified and repaired first, or inspection and maintenance is conducted more frequently at facilities with the greatest leak frequency.

As leaks are identified, measured, and repaired, operators should record baseline data so that future surveys can focus on the most significant leaking components. This information will direct subsequent emissions surveys, prioritize future repairs, and track the methane savings and cost-effectiveness of the DI&M program.

Step 4: Develop a Survey Plan for Future DI&M. The final step in a DI&M program is to develop a survey plan that uses the results of the initial baseline survey to direct future inspection and maintenance practices. The DI&M program should be tailored to the needs and existing maintenance practices of the facility. An effective DI&M survey plan should include the following elements:

- ★ A list of components to be screened and tested, as well as the equipment components to be excluded from the survey.
- ★ Leak screening and measurement tools and procedures for collecting, recording, and accessing DI&M data.
- ★ A schedule for leak screening and measurement.
- ★ Economic guidelines for leak repair.
- ★ Results and analysis of previous inspection and maintenance efforts which will direct the next DI&M survey.

Operators should develop a DI&M survey schedule that achieves maximum cost-effective gas savings yet also suits the unique characteristics of the facility—for example, the age, size, and configuration of the facility and the inlet pressure. Some partners schedule DI&M surveys based on the anticipated life of repairs made during the previous survey. Other partners base the frequency of follow-up surveys on maintenance cycles or the availability of resources. Since a DI&M program is flexible, if subsequent surveys show numerous large or recurring leaks, the operator can increase the frequency of the DI&M follow-up surveys. Follow-up surveys may focus on components repaired during previous surveys, or on the classes of components identified as most likely to leak. Over time, operators can continue to fine-tune the scope and frequency of surveys as leak patterns emerge.

Estimated Savings

Savings achieved by Natural Gas STAR partners implementing DI&M programs at gate stations and surface facilities vary widely. Factors affecting results include the number of stations in the DI&M program, the stage of program development (i.e., new versus mature program), and the level of implementation and repair costs. Costs differ between facilities because of the type of screening and measurement equipment used, frequency of surveys, and number and type of staff conducting the surveys.

Exhibit 7 provides a hypothetical example of the costs and benefits of implementing DI&M at three gate stations. The leak rates and number of leaking components in this example are based on actual leak rates reported for three sites in the 1998 EPA/GRI/PRCI study. Exhibit 7 illustrates the type of calculations that distribution partners should make to evaluate whether DI&M could be cost-effective for their operations.

Exhibit 7 illustrates that although the costs of finding and fixing leaks may not be recovered by the value of the gas saved at each and every site, if multiple sites are included in the DI&M program, the overall program can still be profitable. For the hypothetical example in Exhibit 7, DI&M is not cost-effective at Site 2, although DI&M is profitable for the three sites considered as a whole. In this case, the operator would use the experience gained from the baseline survey of Site 2 to direct subsequent surveys; possibly excluding Site 2 from subsequent surveys, screening Site 2 less frequently, or screening only a selected group of components.

Exhibit 7. Example of Estimating the Savings from Implementing DI&M at Gate Stations and Surface Facilities

General Assumptions:	
Leak screening by soaping; 80 components per hour	2 hours x $/hour labor cost
Leak measurement using TVA correlations	1 hour x $/hour labor cost
Hourly labor rate	$50/hour
TVA capital cost	$0 (assume already owned by partner)[1]
Estimated repair life	12 months
Site 1	
Number of leaks	20 leaks (six valves repaired—2 x 30 Mcf/yr; 2 x 10 Mcf/yr; 2 x 1 Mcf/yr)
Hypothetical repair cost	Assume 3 repairs x $10 and 3 repairs at $3
Total gas savings	82 Mcf
Site 2	
Number of leaks (assume fewer leaks to measure)	8 leaks (2x10 Mcf/yr; 6x2 Mcf/yr)
Hypothetical repair cost	Assume 2 repairs x $5; 6 repairs at no cost
Total gas savings	32 Mcf
Site 3	
Number of leaks	16 leaks (1x60 Mcf; 2x30 Mcf; 1x15 Mcf; 6x10 Mcf; 6x1 Mcf)
Hypothetical repair cost	Assume 1 repair x $33; 2 repair x $15; 5 repair x $3; remaining repairs at no cost
Total gas savings	201 Mcf

	Total Survey Cost	**Total Repair Cost**	**Value of Gas Saved ($3/Mcf)**	**Net Savings**	**Payback Period**
Site 1	$150	$39	$246	$57	9.2 months
Site 2	$125	$10	$96	($39)	17 months
Site 3	$150	$78	$603	$375	4.5 months
Total	**$425**	**$127**	**$945**	**$393**	**7 months**

[1]TVAs can cost up to $2,000. Savings from avoided emissions may not support purchasing a TVA.

Partner Experience

From 1995 to 2000, 18 Natural Gas STAR partners reported gas savings from implementing DI&M at gate stations and surface facilities. Three examples are shown in Exhibit 8.

Exhibit 8: Partners' Experience Implementing DI&M at Gate Stations and Surface Facilities

Company A: During 2000, this company surveyed 86 facilities and found leaks at 48 sites. A total of 105 leaks were identified, and 66 leaks (63 percent) were repaired. The total cost to find and fix the leaks was $2,453, an average of $29 per facility surveyed. Total gas savings were 1,519 Mcf per year, worth $6,557 at $3 per Mcf. Total savings from DI&M was $4,104. Net savings were approximately $50 per facility surveyed.

Total Gas Savings	$6,557
Total Survey Costs	$1,700
Total Cost of Repairs	$753
Net Savings	**$4,104**

Company B: Eighteen facilities were surveyed in 1997 for a total cost of $1,080. Fifteen small leaks were identified including 1 flange, 2 swage lock fittings, and 12 small valves. The average leak rate was 17.5 Mcf per year. The 15 leaks were repaired for a total cost of $380, which resulted in gas savings of 263 Mcf per year. At $3 per Mcf, the value of the gas saved was $789. The total cost of the leak survey and repairs, $1,460, was not recovered in the first year. The average survey and repair cost was $60 per facility surveyed.

Total Gas Savings	$789
Total Survey Costs	$1,080
Total Cost of Repairs	$380
Net Savings	**$(671)**

Company C: This company surveyed 306 facilities and identified and repaired 824 leaks. Four leaks were described as "large", seven were described as "medium", and the remaining leaks were described as "small," meaning that an electronic detector or soaping was required to locate the leak. Total survey and repair costs were approximately $16,500, an average of $54 per site surveyed. Total gas savings were 117,800 Mcf, an average of 143 Mcf per leak. Net savings were approximately $1,100 per facility surveyed (at $3 per Mcf).

Total Gas Savings	$353,430
Total Cost of Survey and Repairs	$16,500
Net Savings	**$336,930**

The number of facilities included in partners' DI&M programs ranged from less than 20 facilities to more than 2,100 facilities. Leaks were found at 50 percent of facilities, and an average of two leaks were found per leaking facility. The average emissions saved per leak repair was 100 Mcf per leak.

Partner-reported survey and repair costs varied substantially. Incremental costs for DI&M surveys ranged from "negligible" for partners with ongoing leak inspection programs already in place, to more than $1,200 per facility. The highest DI&M survey costs were reported for large distribution systems in urban areas where labor costs are higher, and the gate stations are presumed to be larger and to have more components. Reported repair costs similarly ranged from negligible for simple repairs made on the spot, to more than $500 per repair.

Lessons Learned

DI&M programs can reduce survey costs and enhance profitable leak repair. Targeting problem stations and components saves time and money needed for future surveys, and helps identify priorities for a leak repair schedule. The principal lessons learned from Natural Gas STAR partners are:

★ To be cost-effective, DI&M at gate stations and surface facilities must use the most low cost and rapid screening and measurement techniques. Soaping, listening for audible leaks, portable gas "sniffers," and TVAs/OVAs are recommended for leak screening. TVA screening concentrations and EPA's correlation equations are recommended as a cost-effective method for estimating mass leak rate, especially if a TVA or OVA is already available at the facility.

★ A small number of large leaks contribute to most of a facility's fugitive methane emissions. Partners should focus on finding leaks at equipment components that are cost-effective to repair. One of the most cost-effective repairs is simply to tighten valve packings or loose connections at the time the leak is detected. Partners have found it useful to look for trends, asking questions such as "Do gate valves leak more than ball valves?"

★ Partners have also found that some sites are more leak-prone than others. Tracking of DI&M results may show that some facilities may need more frequent follow-up surveys.

★ Institute a "quick fix" step that involves making simple repairs to simple problems (e.g., loose nut, valve not fully closed) during the survey process.

★ Re-screen leaking components after repairs are made to confirm the effectiveness of the repair. A quick way to check the effectiveness of a repair is to use the soap screening method.

★ Frequent surveying (e.g., quarterly or twice yearly) during the first year of a DI&M program helps identify components and facilities with the highest leak rates and leak recurrence, and builds the information base necessary to direct less frequent surveying in subsequent years.

★ Record methane emissions reductions for each gate station and/or other surface facilities and include annualized reductions in Natural Gas STAR Program reports.

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United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460

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October 2003

OIL AND GAS GREENHOUSE GAS EMISSIONS REDUCTIONS

FINAL REPORT
December 31, 2007

APPENDIX D

Climate Change Advisory Group Final Report,
Recommendation ES-13 (CO2 Reduction from Fuel Combustion in Oil and Gas)

1) Policy Recommendation (CCAG Report App. H, pp. H-51 to H-54)

2) Preliminary Quantification of GHG Savings and Cost per Ton (CCAG Report Att. H-8)

3) Preliminary Analysis of CO2 Emissions from Natural Gas Fueled vs. Electrically Powered Compressors (CCAG Report Att. H-9)

ES-13 CO2 Reduction from Fuel Combustion in Oil & Gas Operations

Policy Description:

<u>CCAG Summary:</u> There are a number of ways in which CO2 emissions in the oil and gas industry can be reduced, including (1) new efficient compressors, (2) optimize gas flow to improve compressor efficiency, (3) improve performance of compressor cylinder ends, (4) capture compressor waste heat, (5) replace compressor driver engines, and (6) waste heat recovery boilers. Policies to encourage these practices include education and information exchange, financial incentives, and mandates or standards – coupled with cost and investment recovery mechanisms, if appropriate – that require certain practices.

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Given the wide range of costs and technologies involved the CCAG identified three key categories: (1) compressor efficiency improvements, (2) waste heat recovery for compressors and boilers, and (3) replacement of gas-driven compressors with electrical generators. Of these three categories, the focus should be efficiency improvements and waste heat recovery. Compressor replacement was considered a less fruitful area for analysis because (a) new compressors present high costs relative to the GHG reduction potential the provide, and (b) because switching the compressor fuel from gas to electricity simply moves the GHG production – at least in part – to another locale, and evidence indicates that compared to grid average CO2 emissions per kWh at this time, natural gas fueled compressors may emit less CO2 per kWh.[10]

Policy Design:

The CCAG recommends that New Mexico focus attention on reducing GHG emissions from fuel combustion in the oil and gas industry through education, financial incentives, or mandates and/or standards – coupled with cost and investment recovery mechanisms, if appropriate – to: (1) improve the efficiency of compressors; (2) boost waste heat recovery for compressors and boilers including the deployment of CHP systems that could sell excess power back to the grid; and to a lesser extent, (3) replace gas-driven compressors with electrical compressors when doing so reduces CO2 emissions.

The CO2 reduction goals stated below are being provided for the sole purpose of partially meeting the targets set by Governor Richardson's directive and are not necessarily confirmed or validated by any current study or analysis regarding economic or technical feasibility. It is the intent of the CCAG to require further study and analysis of the approaches recommended above by the NMED and other appropriate agencies, and that from this study and analysis, changes in goals and determinations regarding the economic and technical feasibility of these approaches

[10] See Attachment H-9.

may result.

Subject to verification of technical and economic feasibility and reduction potential:

- **Goal levels:** Reduce CO_2 emissions from fuel combustion by 75% by 2020.
- **Timing:** As noted above.
- **Parties:** Oil and gas production, processing, and transportation/distribution companies

Implementation method(s):

Policies to implement these practices could include:

- Information and education.
- Technical assistance.
- Funding mechanisms and/or incentives.
- Voluntary and or negotiated agreements.
- Codes and standards – coupled with cost and investment recovery mechanisms, if appropriate.

Related Policies/Programs in place:

- Some companies may practice the measures outlined above, but there is currently no state or federal requirement for any company to implement any of these measures.

Type(s) of GHG Benefit(s):

- CO2: CO2 emissions would be reduced directly through the implementation of these measures. Methane emissions would also be reduced, but these are addressed in ES-12.

Estimated GHG Savings and Costs Per Ton:

The specified goal level is translated into GHG reductions below. Current uncertainties regarding costs and emission reduction benefits of these approaches inhibit comprehensive and thorough estimation of GHG savings and costs per ton at this time. These shortcomings will be addressed by the NMED-led study referenced in the policy design for ES-13. A preliminary analysis of GHG savings and costs per ton, developed to assist in the Energy Supply Technical Work Group's consideration of ES-13, can be found in Attachment H-8.

#	Policy	Scenario	Reductions (MMTCO2e)			NPV (2007–2020) $ Millions	Cost-Effective-ness $/tCO2
			2012	2020	Cumulative Reductions (2007-2020)		
ES-13	CO2 reduction from fuel combustion in oil & gas operations	Specified goals translated into tons GHG reduced.[11] **(See Attachment H-9)**	.61	1.42	10.63	*Not Estimated*	*Not Estimated*

Data Sources, Methods and Assumptions (for quantified actions):

- **Data Sources**: To be determined by the NMED-led study specified in the ES-13 policy design.
- **Quantification Methods**: To be determined by the NMED-led study specified in the ES-13 policy design.
- **Key Assumptions**: To be determined by the NMED-led study specified in the ES-13 policy design.

Key Uncertainties:

- Data regarding the horsepower, type, location, and grouping of internal combustion engines in New Mexico was not available in time for this analysis. Also, significant uncertainties exist regarding the cost, applicability, and GHG reduction benefits achievable, particularly with respect to grid access (i.e., access to electricity at compressor sites) and cost, as well as the relative CO2 emissions associated with electric vs. natural gas fueled compressors.
- These and other uncertainties are to be identified, determined, and addressed by the NMED-led study specified in the ES-13 policy design.

Contributing Issues, if applicable:

- Proportionally more natural gas may get to market rather than being consumed or lost in the production and distribution process. This could yield a net payback for producers, and negative cost/ton results (i.e., savings).
- Some of the criteria air pollutant emissions that would have resulted from less efficient compressors may be eliminated, lowering health impacts and associated health costs.

[11] Omission of compressor electrification from this total reflects the concern raised in Attachment H-9 that replacing natural gas fueled compressors at this time may not reduce CO2 emissions because of the current carbon intensity of grid average electricity in New Mexico.

- Decreased emissions of criteria pollutants could lead to relaxation of throughput and production limits that may exist in permits, possibly enabling increased production and profits.
- Operation and maintenance costs may be reduced through the use of electric compressors and automated air/fuel ratio controllers.
- Power generation using ORC CHP systems could yield a payback through the sale of electricity and provide additional power for electric compressor engines where grid connections and power purchase opportunities are available.
- Organic Rankine cycle CHP systems do not require water for steam generation and generate no waste, limiting these indirect environmental impacts. Organic Rankine cycle CHP systems may be more feasible than steam driven CHP systems.

Feasibility Issues, if applicable:

- Available data suggests that installation and operation of all scenarios may be feasible to varying degrees. Additional, more detailed, analysis is necessary to quantify the feasibility of these options.

Status of Group Approval:

Complete.

Level of Group Support:

Unanimous consent.

Barriers to consensus (if less than unanimous consent):

None.

Attachment H-8

ES-13 CO2 Reductions from Fuel Combustion in Oil and Gas Operations – Preliminary Quantification of GHG Savings and Cost per Ton

With little industry data and time available, the following cursory analysis was developed by Mr. Jeremy Nichols to assist in the Energy Supply Technical Work Group's consideration of ES-13. Due to these limitations and current uncertainties regarding costs and emission reduction benefits of these and other potential approaches to reduction CO2 from field operations, a comprehensive and thorough estimation of GHG savings and costs (or savings) per ton could not be provided at this time. These limitations, and others as appropriate, will be addressed by the NMED-led study recommended by the CCAG in ES-13.

The oil and gas participants on the TWG do not believe the analysis conducted by Jeremy Nichols is accurate, reflects feasible technologies, or reflects potential opportunities associated with engines located in New Mexico.

Estimated GHG Savings and Costs Per Ton:

#	Policy	Scenario	Reductions (MMTCO2e)			Preliminary NPV (2007–2020) $ Millions	Preliminary Cost-Effective-ness $/tCO2
			2012	2020	Cumulative Reductions (2007-2020)		
ES-13	CO2 reduction from fuel combustion in oil & gas operations	A. Reduce CO2 emissions by 20% through the use of automated air/fuel ratio controllers on natural gas compressor engines greater than 600 horsepower by 2020.	.3	.6	4.7	-52.9	-$11
ES-13	CO2 reduction from fuel combustion in oil & gas operations	B. Reduce CO2 emissions by 25% using organic Rankine cycle CHP systems at natural gas compressor stations.	.3	.8	5.9	28.0	$5
ES-13	CO2 reduction from fuel combustion in oil & gas operations	C. Reduce CO2 emissions by 30% by replacing natural gas fired compressor engines with electric compressor motors (assuming zero-carbon electricity).	.4	1.0	7.1	-95.5	-$13

ES-13	**CO2 reduction from fuel combustion in oil & gas operations**	**Combination of A, B, and C technology options above.**	**1.0**	**2.4**	**17.7**	**-120.5**	**-$7**
ES-13	**CO2 reduction from fuel combustion in oil & gas operations**	**Combination of A and B technology options above.[42] (See Attachment H-9)**	**0.6**	**1.4**	**10.6**	**-24.9**	**-$2**

Data Sources, Methods and Assumptions (for quantified actions):

- **Data Sources**: U.S. EPA; State of New Mexico; State of Texas; U.S. Climate Change Technology Program; ORMAT International; ControlWorx, LLC; Lazaro et al. (2006) *Strategic Emission Reduction Plan for Stationary Oil and Gas Sources in the Four Corners Region*; Liebowitz and Schochet. (2001) "Generating electric power from compressor station residual heat," *Pipeline and Gas Journal,* November 2001.
- **Quantification Methods**: For all three scenarios, the cost/ton of CO2 reduced was initially calculated using data from government and industry. Cost/ton data was extrapolated from the U.S. EPA, state information, supplier data, and supplier data. CO2 reduction goals were established considering (1) the amount of CO2 that could potentially be reduced, (2) availability of technology, (3) cost, and (4) feasibility (with uncertainties noted below). Natural gas savings were factored into the automated air/fuel ratio controller and electric compressor motor installation scenarios based on Mcf savings data from the EPA and suppliers. Net present value was calculated using a 5% annual discount rate of the total overall costs. Cumulative reductions were determined based on linear progress toward meeting the overall reductions for all three scenarios.

  Based on field studies of the use of automated air/fuel ratio controllers in the Gulf of Mexico and EPA data, CO_2 reductions from the use of such controllers were estimated to average 230.9 tons/year/engine. Automated air/fuel ratio controllers have been suggested as a best management practice in the San Juan Basin.[43]

  Natural gas use savings from the use of an automated air/fuel ratio controller come from more efficient startups, decreased fuel use, and increased production. Average natural gas

[42] Omission of ES-13 Scenario C from this total reflects the concern raised in Attachment H-9 that replacing natural gas fueled compressors at this time may not reduce CO2 emissions because of the current carbon intensity of grid average electricity in New Mexico.
[43] Lazaro et al. (2006) *Strategic Emission Reduction Plan for Stationary Oil and Gas Sources in the Four Corners Region*.

savings of 78 Mcf/day have reported[44], as well as increased production rates of between 1% and 6.8%. Fuel savings could yield a payback of as much as $14,235/year per engine at $5 Mcf. Additional costs of operating an automated air/fuel controller, which include electricity costs, are reportedly offset by the reduction in engine maintenance costs, according to suppliers.[45] The cost of an automated air/fuel ratio controller was estimated to be $120,000, based on data provided by the EPA and suppliers.

Organic Rankine cycle ("ORC") CHP systems have been used at compressor stations in Canada, and are being developed for compressor stations along the North Border pipeline in North and South Dakota, according to industry reports.[46] They are also in use at landfills in Texas and Illinois, where waste heat from flares and reciprocating internal combustion engines is used to fuel ORC systems, according to the EPA.[47] These systems range from 1-10 MW. The cost of installing an ORC system to generate power was estimated at $1,000/kW ($1,000,000/MW), and operation and maintenance costs estimated at $1/MWh, based on supplier and industry data.[48] Overall cost is estimated at $40/MWh of output according to suppliers and field studies.[49]

Estimated annual CO_2 reductions using ORC can reach 6,600 tons of CO_2 reduced per MW installed according to suppliers and industry.[50] This could lead to a 6,600 to 66,000 tons/year reduction in CO_2, depending on the size of the ORC system. Using the midpoint of 36,300 ton/year reduction, this would amount to a $9.17 cost per ton reduction in CO_2 emissions, assuming a total operating time of 8322 hours, which is based on the reported 95% availability of ORC systems.[51]

For electric compressor motor conversion, the cost of conversion comes from the capital cost and operation and maintenance costs. Estimates indicate capital costs for a 1,000 hp engine to be $700,000, with around a $500.00 per day electricity cost according to reports from the state of Texas on the use of electric compressor motors within the state.[52] The use of electric compressor motors has been suggested a best management practice in the San Juan Basin.[53]

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44 U.S. EPA. (2004) *Automated air/fuel ratio controllers*. PRO Fact Sheet No. 111.
45 *Supra*.
46 Liebowitz and Schochet. (2001) "Generating electric power from compressor station residual heat." *Pipeline and Gas Journal*, November 2001.
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47 U.S. Climate Change Technology Program. (2005). *Technology Options for the Near and Long Term*. August 2005.
48 Liebowitz, H.M. (2002). *Generating Electric Power from Waste Heat using ORC Technology*. Power Point Presentation prepared for PTAC 2002 Climate Change and GHG Technology. H.M. Liebowitz, Manager, Heat Recovery Systems, ORMAT International.
49 *Supra*.
50 *Supra*, note 3.
51 *Supra*, note 5.
52 Texas Comptroller of Public Accounts. (2004). "East Texas gas company looks to cheaper power solution: Powering the pump." *Fiscal Notes*, August 2004.
53 *Supra*, note 1.

Estimated fuel savings are $1,200/day for a 1,200 hp engine, assuming a natural gas cost of $5/Mcf. Methane emission reductions are reported to be around 2.11 Mcf per year per horsepower converted for electric engines.[54] The replacement of one 3,000 hp compressor engine with an electric compressor is reported to reduce methane emissions by 6,440 Mcf per year.[55] With an average price of natural gas of $5/Mcf, the cost savings average $10.55 per year per horsepower converted. The replacement of one 3,000 horsepower gas-fired engine with an electric compressor could save $32,200/year. Total estimated savings for one 1,000 hp engine are estimated below:

Fuel savings (at $1/hp/day)	Methane emission reduction savings (at 2.11 Mcf/year/hp)	Total daily savings	Total yearly savings
$1,000/day	$28.90/day	$1,028.90	$375,548

Projecting from 2007 to 2020, the total estimated savings of replacing one 1,000 hp engine with an electric compressor are shown below:

Costs/year (with capital cost)	Savings/Year	Net Savings/Year
$236,346	$375,548	$146,382

Assuming an emission rate of 56,100 tons CO2/Mcf, based on EPA AP-42 factors for reciprocating internal combustion engines, and an average throughput of 10,000 Mcf/year, one 1,000 hp compressor engine can release as much as 5,610 tons/year. A payback of $26.09 is estimated for every ton of CO_2 reduced when considering estimated savings.

- **Key Assumptions**: It was assumed that the scenarios above represent the most effective approaches to achieving the policy objective of ES-13. This assumption was based on cost, CO2 reductions, and available data. There may be other effective scenarios, and/or additional information may suggest less effectiveness for above scenarios.

  The above estimates above assume a flat production rate until 2020, i.e, that expanded production efforts will balance out declining production from existing fields. A consistent emission rate of 3.9 MMtCO2/year was assumed based on emission data for field use of natural gas and natural gas processing included in the reference case forecast prepared by Michael Lazarus. A $5/Mcf cost for natural gas was used to estimate savings. Consistent costs across equipment types and sizes were assumed for the purposes of this assessment. It was assumed that the technology required for implementing the scenarios above are readily available and readily adaptable to natural gas production in New Mexico. Other assumptions are as noted above.

Key Uncertainties:

- For automated air/fuel ratio controllers, it is uncertain exactly how many compressor stations could be equipped with this technology and how many controllers would be required. Data

[54] U.S. EPA. (2004). *Install electric compressors*. PRO Fact Sheet No 105.
[55] *Supra*.

regarding the horsepower, type, location, and grouping of internal combustion engines in New Mexico was not available in time for this analysis.

For ORC CHP systems, it is uncertain how many systems would be required and where such systems would be most feasible and effective. Although baseline research and development appears well-developed, additional research and development costs to specifically apply ORC to facilities in New Mexico may arise. It is also uncertain what degree of payback may be expected through the sale of electricity from ORC CHP systems.

For electric compressor motors, it is uncertain what level of feasibility exists within the producing areas of New Mexico and how many compressor engines could be cost-effectively replaced. Data on the availability and accessibility of electric power was not available in time for this analysis. It is also uncertain what the potential costs of transmission line and/or substation construction, if any, and increased power generation would be.

Savings may also vary depending on future natural gas prices and throughput.

Attachment H-9

ES-13 CO2 Reductions from Fuel Combustion in Oil and Gas Operations – Preliminary Analysis of CO2 Emissions from Natural Gas Fueled vs. Electrically Powered Compressors

The following preliminary analysis was developed by Mr. G. Reid Smith to assist in the Energy Supply Technical Work Group's consideration of ES-13. Its conclusion suggests that compared to grid average CO2 emissions per kWh at the present time, fueling a mid-size compressor engine (Caterpillar 3508) with natural gas may result in 32% less CO2 emissions. Similar analyses should be conducted for other size engines and may corroborate this conclusion. Updated emissions information reported by the Natural Resource Defense Council shows "grid average" CO2 emissions of 1.491 lbs/kwh and 1.717 lbs/kwh for PNM and Excel respectively (not restricted to New Mexico) - both of which represent improvement over the 2.02 lbs/kwh figure below, but which remain above the 1.366 lbs/kwh calculated for an engine fueled by natural gas. This may suggest that, at this time, replacement of gas fired engines with electrically driven compressors is a poor idea from a carbon standpoint.

ES-13 Preliminary Analysis of CO2 Emissions from Natural Gas Fueled vs. Electrically Power Compressors				
A.	New Mexico Average Electric Generation; **CO2 lbs/kwh** (Source: EIA, *Updated State-level Greenhouse Gas Emission Coefficients for Electricity Generation 1998-2000*)			2.02
B.	Cat G3508 LE Fuel Usage; BTU/kwh (Source: Derived below as illustrated.)			10,710
C.	Methane; BTU/SCF (Net heating value, i.e., usable BTUs)			909.4
D.	Cat G3508 LE Fuel Usage SCF/kwh (Source: Derived below as illustrated.)			11.777
E.	Cat G3508 LE **CO2 lbs/kwh** (Source: Derived below as illustrated.)			1.366
Derivations:				
F.	11.3	MJ/kwh	From Cat Specification Sheet	
G.	947.82	Btu/MJ	From Google "on-line" conversion tool	
H.	10,710.348	BTU/kwh	Row F time Row G	
I.	11.78	SCF/kwh derived for G3508 LE	Row H divided by Row C	
J.	379.48	SCF/mole		
K.	16.01	MW - methane		
L.	44	MW - CO2		
M.	0.497	lbs methane/kwh		
N.	1.366	lbs CO2/kwh (the ratio of MW's times the methane lbs/hr)	(Row L divided by Row K) time Row M	
Conclusion:				
O.	CO2 Intensity Ratio: Natural Gas Fired Engine to Electric Driven Engine		Row E divided by Row A	**0.68:1**

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APPENDIX E

Climate Change Advisory Group Final Report, Attachment D-2: Fossil Fuel Industry Emissions

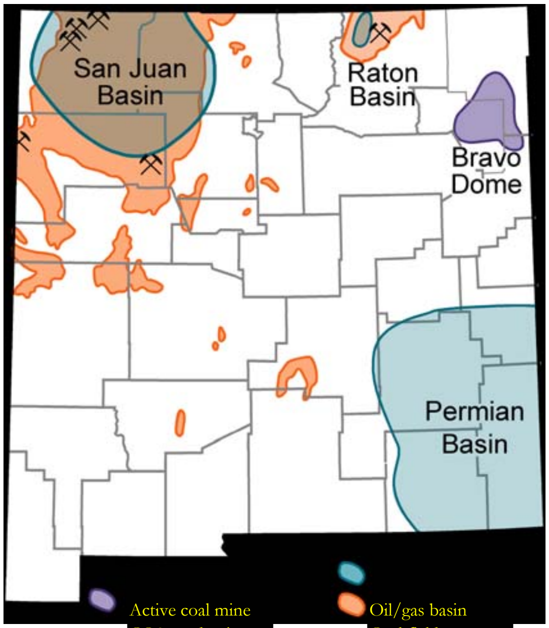
Correction: NMED has been requested by Roger Fernandez, manager of the US EPA Gas STAR program, to provide a correction to Footnote 35, page D-35. Mr. Fernandez indicates that the information attributed to him should state that he estimates total methane emissions by the oil and gas industry in New Mexico to be approximately 20 Bcf.

Attachment D-2. Fossil Fuel Industry Emissions[32]

The oil and gas industry has played an instrumental role in New Mexico's economy and livelihoods for more than 70 years. Oil and gas revenues currently provide about 20% New Mexico's General Fund -- down from historic highs of nearly 90% -- and the industry provides employment for about 10,000 New Mexicans.[33] The State currently ranks second in the nation in natural gas production and fifth in crude oil production.[34] It is also a leader in both the production and reserves of carbon dioxide, which is used largely for enhanced oil recovery.

Natural gas production is concentrated in the northwestern corner of the State (San Juan Basin), while oil production occurs predominantly in the southeast (Permian Basin). (See Figure D-12) As of 2002, over 700 oil and gas industry-related companies operated in the State, working 21,771 oil wells, 23,261 gas wells, 456 CO_2 wells, 4,097 enhanced recovery injection wells and 597 salt water disposal wells.[35] In response to expectations of strong US natural gas demands and firm prices, it is expected that another nearly 10,000 gas wells may be drilled in the San Juan Basin in coming years.[36] In addition, there are over 4,500 inactive, non-plugged oil and gas wells that could potentially be returned to production.[37]

Figure D-12. Fossil Fuel and CO2 Producing Regions of New Mexico



Source: **http://geoinfo.nmt.edu/resources/petroleum/**

While coalbed methane (CBM) supplies less than 10% of total US natural gas production, it accounts for nearly a third of New Mexico's natural gas production: 487 of the 1625 billion cubic feet (BCF) produced in 2002.[38] Coalbed methane is found throughout the Rocky Mountain Region, including the Raton and San Juan Basins that span both Colorado and New Mexico. The Fruitland Coal formation of the San Juan Basin is the largest CBM source in the US.

CBM production from the New Mexico portion of the San Juan Basin peaked in 1999 at over 610 Bcf (billion cubic feet), and has since dropped under 500 BCF annually since 2002. At the same time, increased drilling in response to

[32] The Energy Supply Technical Working Group reviewed and accepted the assumptions and results shown in this section.
[33] EMNRD, 2003. *New Mexico's Natural Resources 2003* http://www.emnrd.state.nm.us/Mining/resrpt/default.htm
[34] US DOE Energy Information Agency website. www.eia.gov
[35] ENMRD, 2003.
[36] Bureau of Land Management, 2003. Farmington Resource Management Plan with Record of Decision, December 2003. Farmington Field Office.
[37] EMNRD, 2003
[38] EMNRD, 2003 and data provided separately by the Oil Conservation Division.

expected high demand and prices for natural gas could postpone further decreases in CBM production. Overall, future oil and gas production levels remain highly uncertain, dependent on prevailing oil and gas prices and the potential development of new reserves.

Oil and Gas Industry Emissions

The sheer number and wide diversity of oil and gas activities in New Mexico present a major challenge for greenhouse gas assessment. Emissions of carbon dioxide and methane occur at many stages of the production process (drilling, production, and processing/refining), and can be highly dependent upon local resource characteristics (pressure, depth, water content, etc.), technologies applied, and practices employed (such as well venting to unload liquids which may result in the release of billions of cubic feet of methane annually). With over 40,000 oil and gas wells in the State, three oil refineries, several gas processing plants, and tens of thousands of miles of gas pipelines in the State – and no regulatory requirements to track CO_2 or CH_4 emissions – there are significant uncertainties with respect to the State's GHG emissions from this sector.

At the same time, considerable research – sponsored by the American Petroleum Institute, the Gas Research Institute, US EPA, and others – has been directed towards developing relatively robust GHG emissions estimates at the national level. For the national GHG inventory, US EPA uses a combination of top-down and detailed bottom-up techniques to estimate national emissions of methane from the oil and gas industry (USEPA, 2005). As noted earlier, US EPA has also developed a tool (SGIT) that enables the development of state-level GHG estimates, whereby emissions-related activity levels (numbers of wells, and amount of oil and gas produced) can be multiplied by aggregate emission factors to yield rough estimates of total CH4 emissions. Furthermore, EIA provides estimates of fuel used in New Mexico for natural gas production, processing, and distribution, which enables the estimation of CO2 emissions.

These sources provide a starting point for analysis of New Mexico's oil and gas industry emissions. Additional data and insights have been solicited from industry sources, including the New Mexico Oil and Gas Association (NMOGA) and individual facility managers, US EPA staff, and State agency experts. These sources provided "ground truthing" on several aspects related to State emissions. For example:

- Oil refiners and NMED provided access to permit data that includes estimated fuel consumption. These sources suggest that refinery gas use is over twice the level suggested by EIA data.
- USEPA staff remarked that methane emissions from well venting activities in New Mexico, especially at low pressure CBM sites where the build up of liquids may require venting, appear to be quite significant, perhaps on the order of 40 BCF annually (1.6 million $MMtCO_2eq$).[39]

[39] Personal communication, Roger Fernandez. (It also appears that that some producers have been able modify practices to reduce well venting emissions by about 50%, suggesting a potentially significant source of emission reductions.) This is only one of several significant sources of methane emissions from gas production. The preferred USEPA (SGIT) approach for estimating natural gas production emissions, which involves multiplying national aggregate per well CH4 emissions by the number of New Mexico wells, yields total methane emissions

- NMOGA provided separate estimates for several emissions sources, including carbon dioxide emissions from gas well site equipment (gas combustion in engines, tank heaters, and field separators), and methane and carbon dioxide emissions from venting and flashing activities at field sites. While these data only cover gas production activities in the San Juan Basin, they suggest rates of field gas use (carbon dioxide) and methane emissions that are 50% to 70% higher than the above (EPA-based) estimates. We consider these rates below in a sensitivity analysis.
- Raw gas that emerges from gas and oil wells often contains "entrained" CO_2 in excess of pipeline specifications. This CO_2 is typically separated at gas processing plants and vented to the atmosphere (except in some other states, such as Wyoming and Texas, where it is compressed and transported for enhanced oil recovery).[40] In the case of New Mexico, the CO_2 concentrations of Fruitland CBM are known to be quite significant (currently around 18%), and these concentrations have been rising over time. Data provided by the Oil Conservation Division of EMNRD and NMOGA enable estimates of entrained CO_2 emissions. Though these estimates cover only Fruitland CBM, which accounts for less that a third of New Mexico gas production, it is thought that this is the most significant source of entrained CO2 in the State.
- CO_2 from enhanced oil recovery – In New Mexico, carbon dioxide is extracted from natural formations (Bravo Dome), piped to oil fields, and injected into wells in order to increase yields. Any release of this CO2 during the extraction, transmission, injection, or oil production processes would lead to net emissions to the atmosphere. At the national level, USEPA currently excludes any such emissions from the national inventory, since they are not well understood. In the case of New Mexico practices, NMED is currently looking into available information to assess where any estimates are possible.

Table D-12 provides an overview of the methods used to estimate and project GHG emissions from the various oil and gas sector activities. As shown, a variety of methods were used, in general relying upon local data and guidance from industry and other experts wherever possible.

Several factors will drive future GHG emissions from New Mexico's oil and gas sector, among them:

- Future oil and gas production activity. This is perhaps the most important, yet most uncertain variable that will affect future GHG emissions. One assessment suggests that barring further discovery or development of new reserves, coalbed methane production will remain level for one or two more years, and then begin declining at rate of 13% annually as the fields are depleted.[41] Conventional gas production in the San Juan Basin, under this assessment, would remain flat through the end of the decade, and similarly

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estimates that are significantly less than the national average (per unit natural gas produced), which does not appear justified. Based on discussions with USEPA staff, it was felt that their alternative (SGIT) method – using the New Mexico production-weighted share of national natural gas production methane emissions – would be a better approach for developing initial methane emissions estimates.

[40] On a national level, the USEPA GHG inventory suggests that these entrained CO_2 emissions are quite significant (about 25 MMtCO2in 2002). However, USEPA is still working to systematically incorporate this emissions source into the national inventory, given concerns about double counting emissions in locations (outside New Mexico) where this CO_2 may be used for enhanced oil recovery.

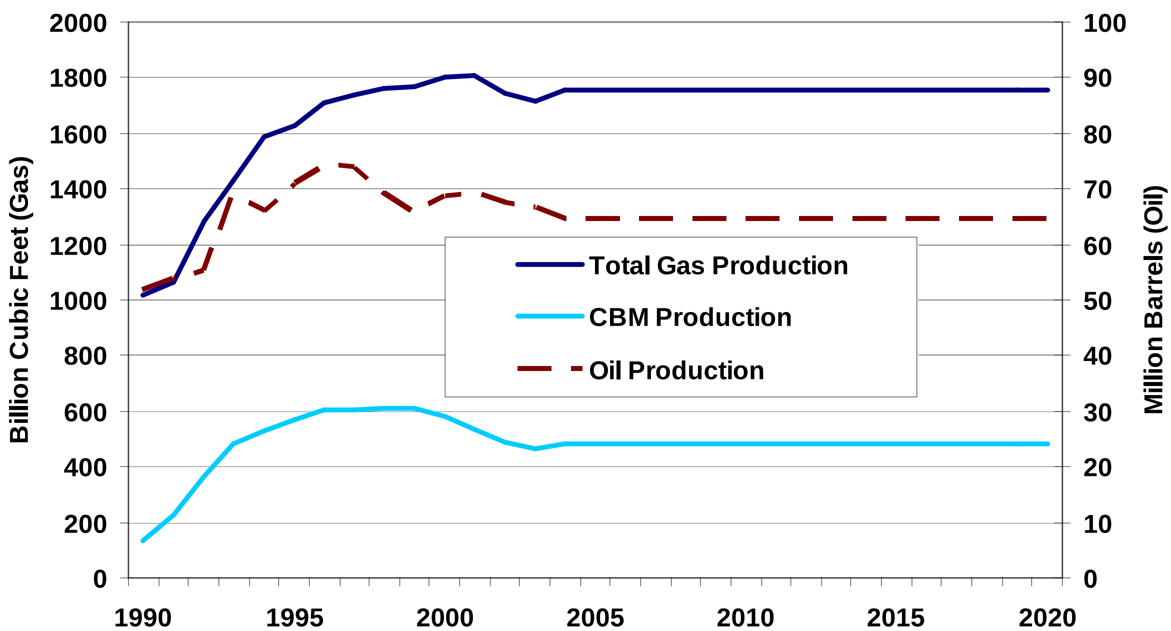
[41] Bernstein Research Call, May 27, 2005.

begin declining at 13% per year. (This assessment covered only the San Juan Basin)

Not surprisingly, there are many competing views on the future of oil and gas production, and prognostications of declining production have been made in the past. Total statewide natural gas production has been relatively steady from 1997 to 2004, varying by less than 6% over this 8-year time period. Thus another possible scenario is that additional reserves are found and exploited such that production remains constant through 2020. The Energy Supply Technical Working Group evaluated the differing views on future oil and gas production and came to the conclusion that the most likely was that emissions remain constant in the sector, and this assumption was used in preparing this inventory.

The implications of this assumption in terms of oil and gas production are depicted in Figure D-13 below.

Figure D-13. Future Oil and Gas Production



- Number of operating wells. As many of the oil and gas fields play out, more operating wells may be needed to maintain production levels. Some emissions, fugitive methane in particular, may depend on the number of operating wells as much as on total oil and gas production. The projected increase in the number of operating wells is based on the estimates contained in the BLM’s Resource Management Plan for the San Juan Basin. Note that this estimate will likely need to be adjusted to correspond to the oil and gas production scenario chosen above.

- Changes in production, processing, and pipeline technologies and practices. In response to industry and USEPA emission reduction initiatives (e.g. GasStar), as well as technological advancements, progress has been made in lower GHG emissions per unit of oil and gas produced and delivered.   Further improvements are likely, but have not been estimated for this initial analysis.

Key assumptions are noted in Table D-11.

Table D-11. Key Assumptions for the Oil and Gas Sector Projections

Parameter	Assumption
Natural Gas and Oil Production	Flat oil and gas production through 2020 See text for details
Oil Refinery Production	No changes in refinery activities (or emissions) are presently assumed.
GHG emissions per unit input/output	Potential emissions savings particularly for methane could be considerable, but are not considered here due to lack of information.

Coal Production Emissions

Methane occurs naturally in coal seams, and is typically vented during mining operations for safety reasons. This methane is typically referred to as “coal mine methane” in contrast coal bed methane, which is associated with coal seams (such as Fruitland) that are not expected to be mined.

Historical coal mine methane emissions were estimated using the EPA SGIT tool, which multiplies coal production times an average emission factor, depending on the mine type. Coal mine methane emissions are considerably higher, in general, per unit of coal produced, from underground mining than from surface mining.

As of 2003, six surface mines were operation in New Mexico. In 2001, underground operations commenced at the San Juan coal mine, and since then surface operations at one other mine (Ancho) has been significantly curtailed. The increasing share of underground coal in recent years has led to an increase in estimated coal mine methane emissions from about 0.2 MMtCO2e to 0.7 MMtCO2e.

Future coal mine methane emissions will depend on the extent to which operations continue to move underground (which could increase emissions significantly) and/or new coal mining operations change in response to demands from the power market. No effort has yet been made to estimate these potential changes.

Table D-12. Emissions Sources and Estimation Methods for the Oil and Gas Sector

Activity	Emissions Source	Approach to Estimating Historical Emissions	Projection Approach
Natural Gas Drilling and Field Production	CO_2 from field use of natural gas	EIA data	Changes with number of operating wells. (CH_4 emissions savings due to further NG Star activity not considered).
	CH_4 from leaks, venting, upsets, etc.	NM share of national emissions (based on total production). EPA staff separately estimate 40 BCF CH_4 (1.6 MMtCO2e) could result from well venting alone.	
Natural Gas Processing	CO_2 from fuel use in gas processing	EIA data	Changes with total statewide gas production or for the case of entrained CO2, with Fruitland gas production. CO_2 concentrations of Fruitland CBM are assumed to increase based on recent trends.
	CO_2 released fro entrained CO_2	Based on NMOGA estimates of CO2 concentration, and NM Oil Conservation Division estimates of gas production, for the Fruitland CBM field. No estimates made for other gas production sources.	
	CH_4 from leaks, venting, upsets, etc.	NM share of national emissions (based on state vs. US production)	
Natural Gas Transmission and Distribution	CO_2 from fuel use (pumps, compressors)	EIA data	Distribution emissions grow with state gas consumption. No changes currently assumed for transmission-related emissions. Could decrease due to further NG Star activity.
	CH_4 from leaks, venting, upsets, etc.	NM share of transmission & distribution national emissions, based on NM share of national transmission line mileage (transmission) and natural gas consumption (distribution)	
Oil Production	CO_2 from fuel use	EIA data	Grows with state oil production.
	CH_4 from leaks, venting, upsets	SGIT tool.	
Oil Refining	CO_2 from on-site fuel use (refinery gas and natural gas)	Based on fuel use and capacity as reported to NMED in permit data. No annual variations considered.	Grows with oil refinery output.
	CH_4 from leaks and combustion	SGIT tool (included with production above)	
Oil Transport	CO_2 from field use of natural gas	No estimates available	Grows with state oil production.
	CH_4 from combustion	SGIT tool (included with production above)	
Carbon Dioxide Production	CO_2: Fugitive Losses	Not included/no information available.	n/a
	CO_2: Enhanced Oil Recovery	Not yet estimated	n/a
	CO_2: Other uses (shown with industrial process emissions)	Production data. Assume only 1% is for non-oil recovery applications (EMNRD as cited in USEPA, 2005).	No changes assumed.

Overall Results

The resulting emissions estimates for the fossil fuel industry are shown in Table D-13 below. As shown, total fossil fuel industry emissions are quite significant, increasing from 15 to nearly 20 MMtCO2e during the 1990s, largely as the result of increased gas production, and in particular of coalbed methane, which led to an increase in the release of entrained carbon dioxide by over 4 MMtCO2. As shown in this table, GHG emissions would likely remain near 2000 levels through 2020, assuming no new and major efforts to reduce fuel use and/or emissions.

Table D-13. Emissions Estimates for the Oil and Gas Sector, by Source and Gas, 1990-2020 (Scenario A)

(Million Metric Tons CO2e)	1990	2000	2010	2020	Explanatory Notes for Projections
Fossil Fuel Industry	**15.2**	**19.5**	**20.3**	**20.7**	
Natural Gas Industry	**12.7**	**17.0**	**17.3**	**17.7**	
Production					
Fuel Use (CO2)	1.8	2.0	1.9	1.9	grows with gas production
Methane Emissions (CH4)	1.9	3.4	3.7	3.7	grows with gas production
Processing					
Fuel Use (CO2)	1.9	2.1	2.0	2.0	grows with gas production
Methane Emissions (CH4)	0.8	0.8	0.9	0.9	grows with gas production
Entrained Gas (CO2)	0.8	5.0	5.2	5.6	grows with CBM prod & CO2 concentration
Transmission					
Fuel Use (CO2)	4.2	2.3	2.3	2.3	no change assumed from 2003 on
Methane Emissions (CH4)	1.0	0.9	0.9	0.9	no change assumed from 2003 on
Distribution					
Fuel Use (CO2)					included in transmission (above)
Methane Emissions (CH4)	0.4	0.4	0.3	0.4	grows with gas consumption
Oil Industry	**2.3**	**2.3**	**2.3**	**2.3**	
Production					
Fuel Use (CO2)					included in industrial oil use (above)
Methane Emissions (CH4)	0.7	0.7	0.7	0.7	grows with oil production
Refineries					
Fuel Use (CO2)	1.6	1.6	1.6	1.6	assumes no major changes
Methane Emissions (CH4)					included in oil production (above)
Coal Mining (Methane)	**0.2**	**0.2**	**0.7**	**0.7**	no change assumed from 2003 on

These results as noted earlier are highly sensitive to several assumptions, most notably emissions rates associated with natural gas production activities and future trajectories for oil and gas production. If the emissions rates estimated by NMOGA for oil and gas activities in the San Juan Basin (in 2002) are assumed to apply for all gas production activities in the State, then natural gas production emissions would be about 3 to 4 MMtCO2e higher than shown in Table D-13.[42]

[42] Estimated emissions for 2002 (not shown) would be 2.5 MMtCO2e higher for methane, and 0.9 MMtCO2e higher for carbon dioxide.

Major Uncertainties and Other Issues

The uncertainties in emissions for the fossil fuel industry are perhaps more significant than in any sector other than forestry. Methane emissions and entrained carbon dioxide emissions in gas production and processing represent over half of these emissions. However, these emissions are not directly monitored and can only be estimated using industry assumptions. Field practices can vary considerably, e.g. with respect to flashing and venting, depending on the operator and the resource involved, and there is no monitoring of these practices. There are also significant with respect to methane emissions in transmission and distribution systems, since there is no systematic monitoring and emissions from venting and leaks can vary considerably from site to site.

In addition, significant uncertainties remain with respect to:

- The quality of historical data on field, processing, and pipeline use of natural gas.

- CO2 emissions from enhanced oil recovery, which have not been estimated.

- Refinery fuel use. EIA indicates less than half the refinery fuel use as indicated by refinery permit data.

- Coal mine methane. More accurate estimates would require mine-specific measurements.

Description of Sources of Methane emissions in the Oil and Gas Industry
Excerpted from the US national GHG inventory (USEPA, 2005)

Petroleum Systems

- *Production Field Operations*. Production field operations account for over 95 percent of total CH_4 emissions from petroleum systems. Vented CH_4 from field operations account for approximately 83 percent of the emissions from the production sector, fugitive emissions account for six percent, combustion emissions ten percent, and process upset emissions barely one percent. The most dominant sources of vented emissions are field storage tanks, natural gas-powered pneumatic devices (low bleed, high bleed, and chemical injection pumps). These four sources alone emit 79 percent of the production field operations emissions. Emissions from storage tanks occur when the CH_4 entrained in crude oil under pressure volatilizes once the crude oil is put into storage tanks at atmospheric pressure.
- *Crude Oil Transportation.* Crude oil transportation activities account for less than one percent of total CH_4 emissions from the oil industry.
- *Crude Oil Refining*. Crude oil refining processes and systems account for only three percent of total CH_4 emissions from the oil industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the refineries.

Natural Gas Systems

- *Field Production*. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, gathering pipelines, and well-site gas treatment facilities such as dehydrators and separators. Fugitive emissions and emissions from pneumatic devices account for the majority of emissions. Emissions from field production accounted for approximately 34 percent of CH_4 emissions from natural gas systems in 2003.
- *Processing*. In this stage, natural gas liquids and various other constituents from the raw gas are removed, resulting in “pipeline quality” gas, which is injected into the transmission system. Fugitive emissions from compressors, including compressor seals, are the primary emission source from this stage. Processing plants account for about 12 percent of CH_4 emissions from natural gas systems.
- *Transmission and Storage*. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the United States transmission system. Fugitive emissions from these compressor stations and from metering and regulating stations account for the majority of the emissions from this stage. Pneumatic devices and engine exhaust are also sources of emissions from transmission facilities. Natural gas is also injected and stored in underground formations, or liquefied and stored in above ground tanks, during periods of low demand (e.g., summer), and withdrawn, processed, and distributed during periods of high demand (e.g., winter). Compressors and dehydrators are the primary contributors to emissions from these storage facilities. Methane emissions from transmission and storage sector account for approximately 32 percent of emissions from natural gas systems.
- *Distribution*. Distribution pipelines take the high-pressure gas from the transmission system at “city gate” stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. Distribution system emissions, which account for approximately 22 percent of emissions from natural gas systems, result mainly from fugitive emissions from gate stations and non-plastic piping (cast iron, steel). An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced the growth in emissions from this stage.

OIL AND GAS GREENHOUSE GAS EMISSIONS REDUCTIONS

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APPENDIX F

Policy Options for Oil and Gas Emissions Reductions (DRAFT)
Dominique Gomez, NMED Public Policy Fellow
August 2007

NOTE: The following was written by Dominique Gomez, a Public Policy Fellow working at NMED during spring and summer of 2007. She was asked to prepare a list or catalog of all conceivable policy options for implementing greenhouse gas reductions from oil and gas processes. This list has not been edited by NMED and does not represent any policy decision by NMED, but is provided for informational purposes only.
- Brad Musick, NMED Air Quality Bureau

Background:
It seems that the main barriers to implementation of many of the available technologies to reduce the greenhouse gas emissions in the oil and gas industries are financial. Although many of the available and recommended technologies are money savers, and even have relatively short payback periods, the initial investment does not make financial sense to many companies without additional incentives or requirements.
The idea is thus to provide incentives or financial aid to offset the initial costs of implementing new technology. An obvious alternative would be to require the changes, thus leveling the playing field for industries within the state. The best option may be a combination of the two approaches: require some specific retrofits or use of new technology while providing incentives for others.
In addition to technology, some training and encouragement of better maintenance may help to reduce emissions as well. Like installing retrofits and new technology, higher maintenance standards can either be mandated by regulation or encouraged through financial incentives.
Following are some possibilities for ways to offer financial incentives:

Method of Reduction	**How it works**	**Examples of implementation**	**Pros**	**Cons**	**Comments**
Revolving Loan Fund (RLF)	A fund is set aside which businesses can apply to use for relevant projects. Other loans can then be made through repayments and interest on the initial loans. The initial investment will only be recouped if no more applications for projects are made.	EPA's Drinking Water State Revolving Fund http://www.epa.gov/safewater/dwsrf/index.html ; Cascadia Loan Fund	Does not take an extremely large initial investment; Compared to standard loans, RLFs usually have lower interest and take on higher risk	Not the most time efficient method; Most entities will have to wait for loans to be repaid before beginning their own; Not well suited for long-term	

		http://www.cascadiafund.org/)	projects.	projects.	
Break on Regulation – Shorter Reporting Form	Companies that comply with targets on time are given the option of quicker regulation requirements.	EPA's Toxic Release Inventory http://www.epa.gov/tri/tridata/modrule/phase2/forma.htm	Does not take large investment; will actually save department time and money	Depending on difference between regulations, may not be large incentive; department must meet regulatory duty.	
Educational Programs to decrease emissions through behavioral change	Educational guides or classes can be made available to all companies to reduce emissions through behavioral change, especially increased maintenance	This is a recommended step by EPA's Gas STAR program: http://epa.gov/gasstar/bmp.htm	Does not involve costly new technology; better maintenance will benefit business in other ways	May not make significant impact if best practices are already implemented	Should probably be part of strategy, but not main component.
Subsidies for New Technology/ Retrofits	Subsidies, or grants, are provided for companies to invest in more efficient technology. Can also come in the form of a tax credit or deduction. *Flexibility*: Subsidies can cover anything from more efficient refrigerators to much larger and more expensive pieces of equipment.	Energy Policy Act of 2005 for Qualified Hybrid Technology;	Allows companies that might not otherwise be able to afford new technology to purchase it;	Offered uniformly, companies that may be able to afford or were planning to purchase technology may rely on grant;	
Carbon Tax	A standard tax is placed on emissions of greenhouse gases that comes from the burning of fossil fuels. In this case, can be placed on supply side industry.	(Consumer side tax): Boulder, CO Initiative 202; Sweden since 1991; Other	Will not lead to the same price fluctuations that cap-and-trade policies could	As only state wide, will put New Mexico at a disadvantage	For some (albeit very pro-carbon tax) information,

		Scandinavian countries	create; many possibilities for creative use of funds generated		see http://www.carbontax.org
Cap and Trade Policies	An upper limit is placed on the amount of carbon emissions a company can produce. Companies able to reduce below the cap can trade their extra emissions to other companies for profit. *Flexibility* – Allows for flexibility on whose emissions are capped (upstream/downstream)	1990 Clean Air Act SO_2 provision;	Because of cost differential in reduction, cap and trade may be more cost efficient than simple reduction mandates;	Will tax more heavily on those unable to reduce; may cause price fluctuations during times of high energy demand	
Transparency Requirement	GHG reporting is already being required, the level of transparency for these reports, however, is still being decided. High levels of transparency can help to encourage reduction.	EPA's 1986 Emergency Planning & Community Right to Know Act	No financial investment needed.	No guarantee of reduction. Will mostly rely on public pressure to reduce; will most likely have strong opposition from some industries.	Does not allow for much privacy
Tax Credits for production of renewable energy	A set amount of money can be credited in state taxes based on the production of energy from renewable sources.	Federal Energy Policy Act of 2005; New Mexico's Renewable Energy Tax Credits	Could encourage oil and gas industry to begin investing in this new field/	Many such programs are already in place, including several in New Mexico;	
Tax Incentive	The EPA Gas STAR Program is a		Program is	Only targets	

for Participation in EPA's Gas STAR	voluntary partnership between the EPA and oil and gas industry to promote the use of low cost and effective technologies that reduce methane emissions.		already in place; research backing costs and effectiveness of technology already provided;	methane; industry has historical reasons to mistrust EPA	
Legislation requiring reduction	State legislation requires reduction of GHG emission by a set percentage over a set period of time.		If all industry required to do so, playing field will be level; standard procedure for making change	Does nothing to help industry; may hurt smaller industries or industries with special reasons for emissions; may be more costly than voluntary scheme	

Longer analysis of options:

Revolving Loan Fund
A Revolving Loan Fund is a fund of money that is offered to companies to help with initial costs of new initiatives. Amounts may vary based on need and availability. In general, the interest on the loan is substantially lower than commercial loans. As the loan is paid back, the money is then used to fund new companies. Thus, a relatively small amount of initial capital is used over time to fund initiatives at many different companies.
How it would work in this case:
A revolving loan fund to reduce greenhouse gas emissions would work by helping companies with the initial costs involved in updating relevant technologies. Although most oil and gas companies can currently afford many of the retrofits and technological implementations (such as those suggested by EPA's Gas STAR), changes have often not been made up until this point because of a concern for missed opportunity costs.
One drawback of this policy tool is that progress, or the number of companies served, is slower than would be with a larger capital fund. A revolving loan fund approach would most likely only be suitable for shorter term projects, such as ones that have a payback of less than one year.
Estimation of costs:
Cost of administering the program may be covered by the interest from the revolving loan fund. The amount of capital initially placed in the revolving loan fund can vary based on how many companies should be served in a given period, and what amount of capital is awarded to each company.
What it could be used to fund:
Retrofits
Subsidy when building new facility to have most efficient technology
To begin new programs to sequester carbon
Research and Development in relevant areas
Cost of getting into Climate Registry?
Timeframe:

Because a revolving loan fund offers loans in rounds, the time frame for this approach is longer than a larger one-time widely available grant or incentive.

Subsidies for New Technology

Providing a subsidy for new technology that will reduce greenhouse gases may have similar effects as the revolving loan fund action, but will allow companies to access this money on their own schedule without the restraints as the RLF. Because it provides money to more companies at one time, it will have a larger initial impact but will also have require more money up front.

What it could be used to fund:

Much like a revolving loan fund, the money from new technology subsidies could be used to fund a wide variety of retrofits or other new equipment. A list of qualifying equipment could be created and frequently updated, or any equipment that falls under certain requirements could qualify. The list of methane-reducing technology provided by EPA Gas STAR is certainly a start, although other implements should also certainly be considered.

Carbon Tax

Passage of a carbon tax would place a cost on the emissions of carbon produced from the use of natural gas, coal and oil. A carbon tax has already been put in place in several countries including Sweden, and in the town of Boulder, CO. Proponents say that a carbon tax will shift use of fossil fuels towards renewable energy much more effectively than simply providing tax incentives or subsidies on renewable energy. Tax money that is collected can be used in a variety of ways to further reduce greenhouse gas emissions, otherwise mitigate the effects of climate change, or to reduce the effect of the carbon tax on less-affluent families.

One scenario reports that a uniform rebate to all families paying carbon taxes will help less affluent families (who by virtue of having smaller houses and in general using less energy) to completely, or near completely, cover the extra cost of the carbon tax. A similar strategy could help smaller companies with the costs of a carbon tax. Taxes could be set on either production or usage.

http://www.carbontax.org/

Cap and Trade Policies
Currently in plan for New Mexico (?). This strategy places a maximum amount of carbon emissions on a given company (perhaps by amount of energy produced, or a baseline of a given year). Companies that then reduce carbon emissions more than required are allowed to “sell” this amount of carbon to other companies that have not reduced. A similar system is already in place in the European Union.
Proponents of cap and trade say that this system will ease the strain on companies by allowing those who can reduce more readily to reap the financial benefits while providing a safety net for companies that find it difficult to heavily reduce right away. Opponents say that a cap and trade system will create high fluctuations in energy prices, leading to more energy crises.

Transparency Requirement
There is some evidence to believe that simple transparency will go a long way to reducing the greenhouse gas emissions of many companies if public pressure is sufficient. Greenhouse gas reporting is the first step to using transparency as a tool to push voluntary reduction. Without legislation, however, this information could be considered confidential. Many companies may vehemently oppose full transparency in regards to their greenhouse gas emissions. However, many companies already voluntary disclose greenhouse gas emissions through various registries or other agreements.
It is also not certain that there will be enough public interest in these emissions that companies will be forced to reduce. While public concern over climate change is considerable and continues to grow,
For an article outlining the benefits of transparency, see: http://www.brook.edu/comm/policybriefs/pb161.htm

Tax Incentive for Participation in EPA’s Gas STAR
While participation in EPA’s Gas STAR Program is voluntary, some tax incentive from the state to participate could help reduce emissions of methane. EPA’s Gas STAR is available online at www.epa.gov/gasstar and offers best-practices and an analysis of various technological retrofits to reduce methane. A requirement or financial incentive for companies to participate in this program could help in methane reduction.

Legislation requiring reduction

Legislation that simply requires reduction without any extra provisions for assistance in reduction may be effective. It is clear that programs already in place, such as the EPA Gas STAR program, which offer assistance in voluntary reductions are not completely effective.

OIL AND GAS GREENHOUSE GAS EMISSIONS REDUCTIONS

FINAL REPORT
December 31, 2007

APPENDIX G

The Economics of New Mexico Natural Gas Methane Emissions Reduction

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December 30, 2007

The Economics of New Mexico Natural Gas Methane Emissions Reduction

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"*NMED shall conduct a study of voluntary and mandatory mechanisms for reducing greenhouse gas emissions from oil and gas processes by January 1, 2008 and shall submit such study to the Team, the Clean Energy Development Council, and the Governor by said date. Proposed mechanisms shall reduce methane emissions in oil and gas operations by 20% by 2020 and carbon dioxide emission from fuel combustion*."

(Executive Order 2006-69)

Executive Summary

The Governor's goal of a 20% reduction of methane emissions from oil and gas operations by 2020 is economically feasible. Given current industry characteristics, the estimated methane emission level from the New Mexico natural gas industry is approximately 5.8 million metric tons of CO_2 equivalent. In order to meet the Governor's goal, a reduction of 1.16 million metric tons is necessary by 2020. All segments of the industry contribute, with production being responsible for 64%, processing and transmission being responsible for approximately 15.5% each, and distribution contributing about 5% of total emissions. A variety of programs could be implemented to meet the 2020 goal; however the costs and impacts of the various alternatives are not equal. This report provides an assessment of the impacts of the four natural gas industry segments, as well as a more in-depth analysis of the production segment, the largest contributor of methane emissions. This study finds that with strategies combining clean new wells, retired inefficient wells, and retrofitted high-gas-volume wells, a variety of outcomes may achieve the required goal with a minimal negative economic impact. Specifically, within just the production segment, by the year 2020:

- Shutting in of old natural gas wells may reduce total methane emissions by 6.3%
- With required clean technology on all future wells, an average of 1500 new wells per year will increase total methane emissions by 4.8%, for a net decrease in total methane emissions of 1.5%
- Retrofitting existing gas wells with new technology may reduce total methane emissions by up to 12.8%

The economically appropriate mix of these strategies will depend on trends in natural gas prices: lower gas prices will reduce the number of new wells coming on line and will force more low-efficiency wells to be shut in. This scenario will have to rely heavily on retrofitting. Alternatively, higher gas prices will stimulate new production, but will allow more low-efficiency wells to stay in production. Although this scenario will benefit more from new low-emission wells, reliance on retrofitting will depend on trends in total production levels.

The requirement for clean technologies on new wells is a clear opportunity for regulation. Retrofitting existing wells is a clear candidate for an incentive market-based approach. Combined pressures from the natural gas market and an emissions-credit market may speed the retirement of low-efficiency wells.

Within the other segments, significant reductions are also possible through directed inspection and maintenance (DI&M) programs:

- Up to 11% reduction in total methane emissions from reduced processing segment leaks
- Up to 13% reduction in total methane emissions from transmission segment compressors
- Up to 0.6% reduction in total methane emissions from distribution segment meter and pressure regulating stations

These remediations are cost effective for wellhead prices down to $4.57 per Mcf, or with recovered gas as low as 74% of GasSTAR estimates.

Various incentive and regulatory options are available to accomplish these strategies. Improved data collection will be very important to the selection of appropriate strategies in terms of both economic impact and implementation effectiveness. Collection of consistent and timely methane production and emission data is the first and most urgent task in the success of this program.

1.0 Introduction

The New Mexico Climate Change Advisory Group (CCAG) recognized that there are a number of ways in which reduced methane emission levels can be achieved. The CCAG Final Report (CCAG 2006) cites the Natural Gas STAR Program of the U.S Environmental Protection Agency (EPA-GasSTAR), which documents Best Management Practices (BMPs) and Partnership Reduction Opportunities (PROs) that can reduce methane venting and leaks in the production, processing, transmission and distribution segments of the natural gas industry.

In regards to reducing CO_2 emissions the CCAG Final Report again recognizes that these reductions could come from a number of areas including (1) installing new efficient compressors, (2) replacing compressor driver engines, (3) optimizing gas flow to improve compressor efficiency, (4) improving performance of compressor cylinder ends, (5) capturing compressor waste heat, and (6) utilizing waste heat recovery boilers (CCAG 2006). Furthermore, the CCAG Final Report recommends GHG emissions reductions be achieved through education, financial incentives, mandates and/or standards – coupled with cost and investment recovery mechanisms, if appropriate.

In order to ascertain the best incentive mechanisms to achieve the goals set forth by Executive Order 2006-69 and minimize the social impact, a thorough economic assessment is necessary. This report provides a starting point for such an analysis. Specifically the report:

- Provides an overview of the contributors from each segment within the natural gas industry from wellhead to delivery. The segments include; production, processing, transmission, and distribution. This overview is presented in Section 2
- Provides a more in-depth analysis of production, the natural gas industry segment which contributes the majority of methane emissions. The analysis of the production segment is included in Section 3.

- Provides an overview of potential incentive schemes, which is presented in Section 4.

Finally, Section 5 presents conclusions as well as considerations for additional research.

2.0 Principal Contributors to Natural Gas Emissions

CCAG forecasts of New Mexico natural gas emissions by each of the four segments – production, processing, transmission, and distribution – are shown in Table 1 and graphically in Figure 1, which juxtaposes the contribution of methane (CH_4) to direct carbon dioxide (CO_2) emissions by each segment. The relative importance of each segment to methane emissions is readily apparent in Figure 2. Note that the table presents the impact of methane in terms of an equivalent amount of carbon dioxide. The total volume of methane emissions is actually much less than that of carbon dioxide, but the global warming potential of methane is about 21 times that of carbon dioxide (EPA-Methane).

Table 1 – Forecast New Mexico greenhouse gas emissions by the natural gas industry for 2010 (CCAG 2006)

Natural Gas Production Greenhouse Gas Emissions 2010 forecast in millions of metric tons CO_2 equivalent				
Segment	**Methane emissions**	**CO_2 emissions / source**		**Total**
Production	3.7	1.9	fuel use	5.6
Processing	0.9	2.0	fuel use	
		5.2	entrained gas	8.1
Transmission	0.9	2.3	fuel use	3.2
Distribution	0.3			0.3
Total	**5.8**	**11.4**		**17.2**

Source: (CCAG-Emissions)

The CCAG Final Report includes a top-down inventory in which current emission estimates were allotted to industry segments based on EPA historical distributions. Thus, the actual level of emissions by each segment, or by each emission source within a segment, is not actually measured or reported.

The composition of each industry segment is quite distinct. The production segment in New Mexico is comprised of 506 firms[1]. As such, the producers do not, in general exercise market power and may be considered price takers. However, even within this segment there is substantial variation in producer size.

The processing segment in New Mexico includes 13 firms operating 25 natural gas processing plants (NMED-Plants). Processors hold geographic semi-monopolies and are subject to some government regulation.

The transmission segment in New Mexico has five participating firms. The transmission firms are considered common carriers (pursuant FERC Order 636, as well as subsequent orders) and may or may not be subject to market powers.

[1] Data in the section are from 2006, taken from the downloaded OCD database (OCD 2007)

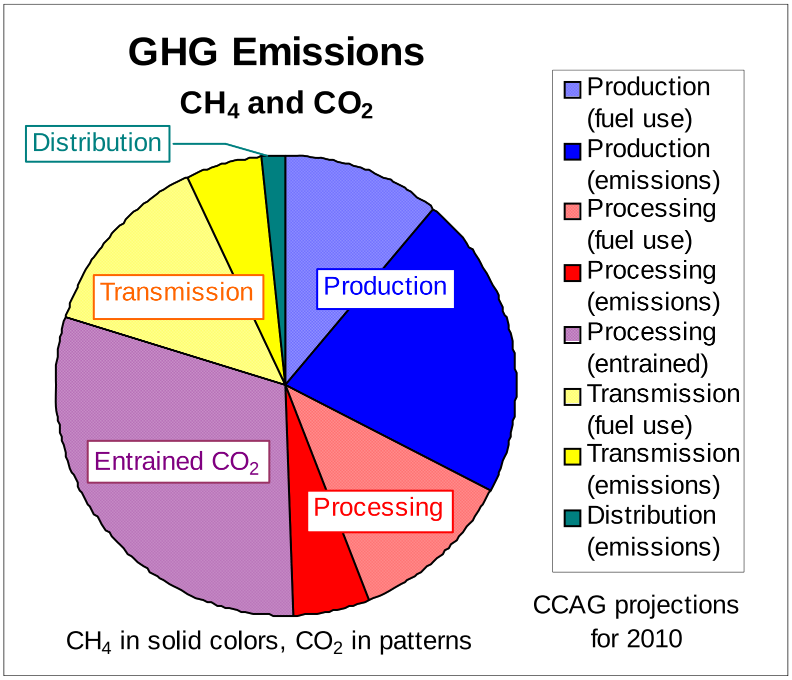

Figure 1– Forecast greenhouse gas emissions by the New Mexico natural gas industry for 2010. Source (CCAG 2006)

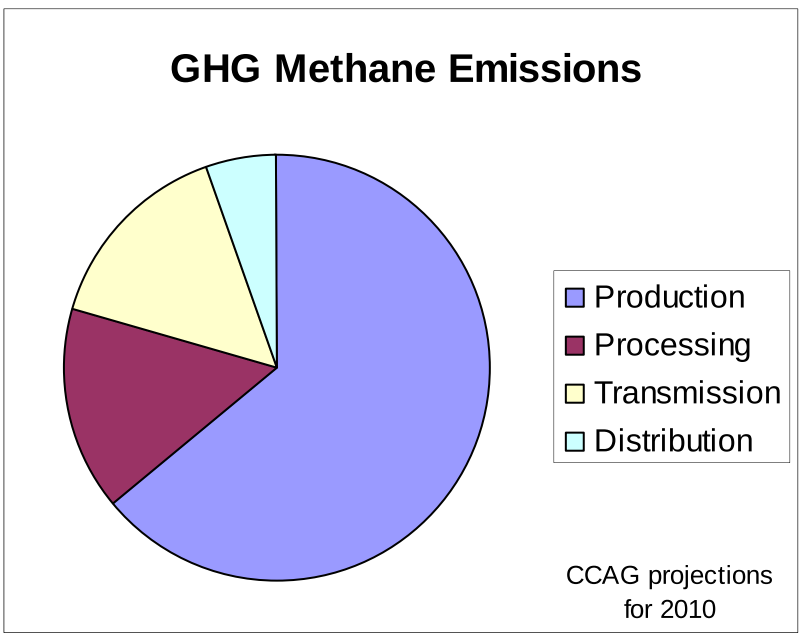

Figure 2 – Forecast methane emissions by the New Mexico natural gas industry for 2010. Source (CCAG 2006).

There are 19 distribution firms in New Mexico: one is tribally owned, one is investor owned, two are privately owned, and 15 are municipally owned. Distribution companies are geographic monopolies and subject to regulation by the State.

The differences and distinct activities of each segment are discussed in more detail in the following sections.

2.1 Natural Gas Production

The production segment contributes nearly 64% of total methane emissions by the New Mexico natural gas industry (see Table 1.) There are three types of natural gas production employed in New Mexico:

well gas - wells producing principally natural gas
casinghead gas – wells producing principally oil with natural gas as a by-product
coalbed methane – (CBM) coal seams producing natural gas with prodigious quantities of entrained carbon dioxide

Additionally, there are three geographic areas of natural gas production in New Mexico, the Raton Basin in the northeast corner of the state, the San Juan Basin in the northwest of the state, and the Permian Basin in the southeast. All three types of wells are found in the San Juan Basin, only CBM wells are in the Raton Basin, and only well gas and casinghead gas are found in the Permian Basin. The number of wells of each type in each county is portrayed graphically in Figure 3. Figure 4 shows the annual gas volume by each type of well for each county. These data are summarized in Table 2.

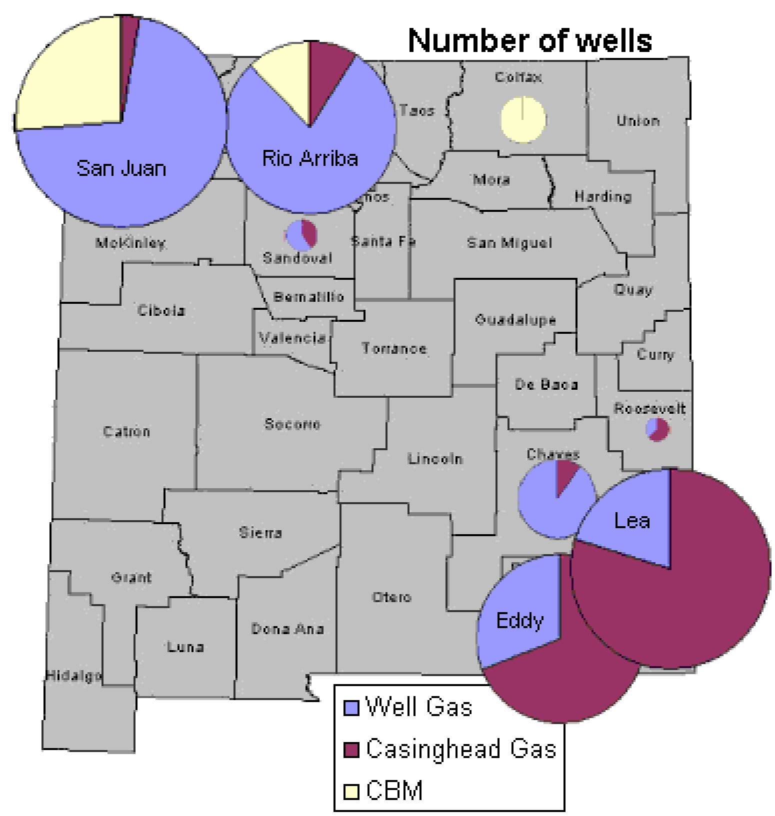

Figure 3 – Gas production by number of wells. Areas are proportional to the number of wells in each county in 2006. Data source (OCD 2007). GIS source (UNM-IARS).

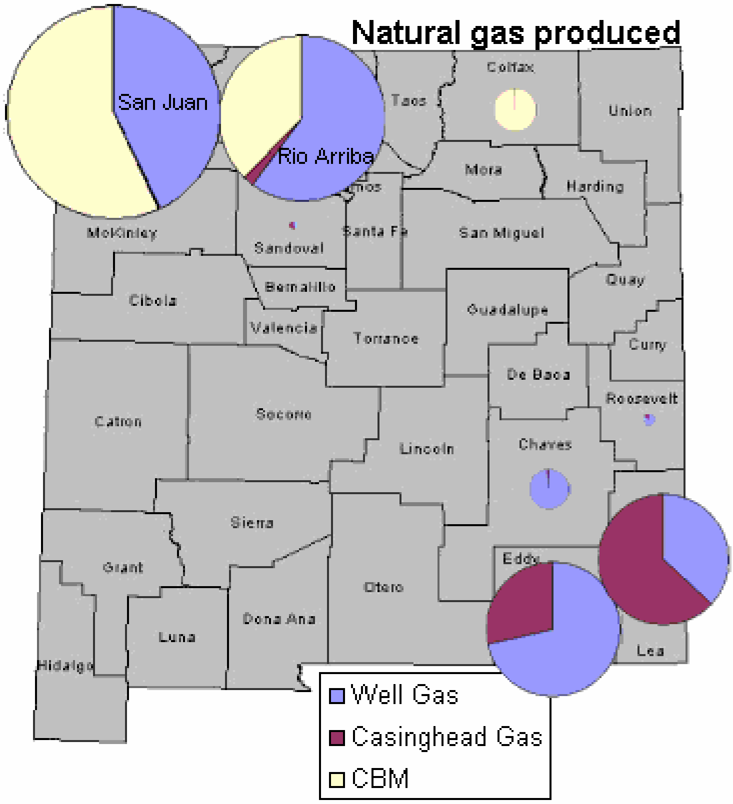

Figure 4 – Well types by volume. Areas are proportional to the 2006 production volume in each county. Data source (OCD 2007). GIS source (UNM-IARS).

Table 2 – Gas production statistics by county.

	Well gas		Casinghead gas		Coal bed methane (CBM)	
County	**# of wells**	**Volume (MMcf)**	**# of wells**	**Volume (MMcf)**	**# of wells**	**Volume (MMcf)**
Chaves	1401	22,933	151	292	0	0
Colfax	0	0	0	0	573	26,393
Eddy	2306	171,506	5120	68,743	0	0
Harding	1	35	0	0	0	0
Lea	2108	87,986	8217	150,838	0	0
Rio Arriba	6049	221,238	704	8,316	942	138,646
Roosevelt	59	2,025	98	407	0	0
San Juan	8085	262,469	327	2,107	3033	349,026
Sandoval	163	517	110	664	1	4

Source: (OCD 2007)

With large variations from well to well, gas at the wellhead may contain large amounts of oil, typical of casinghead gas, to virtually no oil, typical of gas wells and coal bed methane wells. In addition to oil, there may be other liquids, called natural gas condensates, and water. Separation of liquids from gases is typically done at the wellhead. The resulting gas is referred to as raw natural gas.

According to State reporting data, there were 41,211 natural gas-producing wells of all types in New Mexico in 2006. These wells were owned by 506 firms, with ownership ranging from a single well to 6,083 wells. Total natural gas production in New Mexico for 2006 was 1,591,822.525 MMcf (million cubic feet).[2] About 64% of gas-producing wells are classified as gas wells, which includes coal bed methane wells.

Of the 18,913 producing oil wells in 2006, 78% (14,727) of them also produced natural gas. Oil wells contributed 231,365.774 MMcf, or 15% of total natural gas production in 2006. About 36% of gas-producing wells are classified as oil wells.

Production levels drive processing and transmission levels, and affect retail prices, which, in turn, affect levels of distribution.

2.1.1 Sources of greenhouse gases from the production segment

Methane emissions from the production segment account for 64% of the New Mexico natural gas industry totals, and come from gases either intentionally released during completion or during maintenance (vented), or from natural gas leaks (fugitive gas). Completion, the process of venting a new well to clear the shaft of drilling residues, water and waste gases, is a source of intentionally vented methane. According to the EPA/GRI report, the contribution to methane emissions during completions is negligible, particularly for infill wells (EPA/GRI – Venting). Infill wells – wells drilled into already-producing fields – are generally the rule in New Mexico. Carbon dioxide emissions by the production segment, accounting for 17% of the the New Mexico natural gas industry total, are due to fuel-burning. Total estimated 2006 segment emissions of methane are more than 9100 MMcf (CCAG-H7).

The principal sources of methane emissions from the production segment nationally are shown in Table 3. As the largest source of methane emissions in the segment, pneumatic devices will be the focus of greenhouse gas reduction in the production segment.

Table 3 – Principal sources of methane emissions by the production segment nationally.

Source	Pct of segment emissions
Pneumatic devices	37
Fugitive emissions	21
Dehydrators	17
Other	25

Source: (EPA/GRI – Executive Summary)

2.1.2 Economics of greenhouse gas reduction: the production segment

Specific emission reduction strategies that have been considered include refitting or replacing pneumatic devices, directed inspections and maintenance, and installing

[2] 2006 well and production data from (OCD 2007)

plunger lift systems in gas wells (GasSTAR-T&P). The economic feasibility of any of these solutions for methane emission reductions depends on the current price of natural gas, the current costs of production of natural gas and the incremental costs that would be required in order to reduce emissions. In addition to being the major contributor to production segment methane emissions (see Table 3), refitting or replacing natural gas pneumatic systems it is a GasSTAR recommended Best Management Practice for this segment (GasSTAR-BMP) and it is also one of the least costly to remediate.

Pneumatic control systems at many wellheads are driven by natural gas at well pressure. In older devices, gas that is diverted into these systems is ultimately vented to the atmosphere. These are referred to as *high-bleed* devices. The refitting of devices, where appropriate, is estimated to cost $205 per device, while complete replacement is estimated to cost $682 per device, with a recurring annual cost of $30 (GasSTAR-Pneumatics)[3].

Assume that the conversion of high-bleed pneumatic devices to low-bleed would cost $682 (worst case) with a recurring annual cost of $30 and would eliminate an average of 192 Mcf of methane emissions per year per well (GasSTAR-Pneumatics). Amortized over ten years with a discount rate of 5%, that's a total annual cost of less than $141 per well per year. The 192 Mcf/year of recovered gas would increase revenue by a little more than $1186 per annum at the 2006 wellhead price. This represents a net increase in annual revenue of about $1046.

This outcome is consistent with case studies on the GasSTAR web page. The net positive revenue outcome begs the question: why haven't all wells been converted to low-bleed pneumatic systems? There are two possible explanations: 1) most wells with high-bleed pneumatic systems lose much less natural gas than the average, or 2) well operators employ exceptionally large discount rates. The first case may arise if most well operators believe that their own wells are better than the industry average. In the second case, a well operator is indifferent between avoiding an annual expense of $141 beginning this year and annual income of $1187 beginning next when the discount rate is slightly greater than 88%[4]. The petroleum industry is considered somewhat risky, with typical discount rates between 17.9% and 24.5% (Texas 2005). By employing a discount rate of 88%, however, well operators are revealing a level of uncertainty that is much greater than the overall economic uncertainties of the industry.

From a microeconomic or industry perspective, any increased production costs due to emission reductions will result in a shift in the supply curve, making natural gas relatively more expensive. Similarly, increased revenues, as in the example above, result in a supply shift that makes gas relatively less expensive. According to U.S. government figures for 2006, marketed natural gas produced in New Mexico was 1,609,223 MMcf

[3] Remediation costs are taken from GasSTAR, either directly or through (CCAG-H7). Costs quoted in 2001 dollars have been inflation adjusted to 2006.

[4] The present value at discount rate of *r* of avoiding an expense of $141 annually in perpetuity starting this year is $\$141/r$. The present value of an income of $1187 annually in perpetuity starting next year is $\$1187(1/r-1)$. Indifference means that the two present values are equivalent.

from 41,634 wells (EIA-NM)[5], while nationwide production was 19,381,895 MMcf (EIA-National), meaning that New Mexico provides 8.3% of the national supply. Costs imposed on New Mexico producers that are not imposed on producers in other states will result in New Mexico natural gas becoming relatively more costly to produce, which will make it relatively less competitive. Constituting a little more than 8% of the market, however, changes in New Mexico gas supply will have some effect on the national market.

The economic impact of requiring low-bleed conversions to New Mexico natural gas producers can be assessed by estimating the impact on the supply, which in turn impacts the equilibrium price and quantity of natural gas. If price increases and quantity demanded decreases, the number of productive wells will decrease. Similarly, if the price decreases and quantity demanded increases, the number of productive wells will increase.

Requiring low-bleed pneumatic devices on every New Mexico natural gas well may impact the supply of natural gas. The percent change in supply, ΔS, can be estimated by multiplying the price elasticity of supply, ε_s, by the percent change in costs, ΔC, where price elasticity of supply is defined as the percentage change in quantity supplied, given a 1% change in price. That is

$$\varepsilon_S = \frac{\partial Q_S}{\partial P}\frac{P}{Q_S},$$

where Q_S is the quantity supplied at price *P*. To first order, a cost increase can be treated like an equivalent reduction in price, so the percent change in supply then is

$$\Delta S = \varepsilon_S \Delta C\,.$$

The price elasticity of demand is the percentage change in quantity demanded given a 1% change in price, that is

$$\varepsilon_D = \frac{\partial Q_D}{\partial P}\frac{P}{Q_D},$$

where Q_D is the quantity demanded at price *P*. The change in price is determined by the change in supply multiplied by one over the sum of the elasticity of supply and the elasticity of demand. That is

$$\Delta P = \Delta S\left(\frac{1}{\varepsilon_S + \varepsilon_D}\right).$$

[5] Note that the EIA numbers for New Mexico are not quite the same as the OCD numbers. According to Jane Prouty of OCD, these changes are due to differences in timing, pressure bases, and gas content. The EIA figures are used here to put New Mexico supply in context of total market supply.

Price elasticity measures for natural gas supply and demand are taken from (Wiser *et al* 2005) and (Bernstein and Griffen 2005), respectively. The absolute value of the price elasticity of demand is 0.1. Wiser (2005a) estimates an elasticity of supply of 0.83, but indicates a range of estimates of between 0.5 and 1.25 (Wiser 2005b).

Earlier in this section it was found that increased revenue exceeds cost by $1046 *per annum*. Treating this as a negative cost increase (ΔC = –0.5%) in factor cost for a break-even well with revenue of $238,867 (the New Mexico mean), the equivalent increase in supply and decrease in price can be calculated. Assuming the price inelastic nature of demand holds – a 0.1% increase in quantity demanded for every 1% decrease in price – the range of price and quantity changes given the three levels of supply elasticity are shown in Table 4.

Table 4 – Summary of price decrease and supply increase from captured pneumatic device emissions for a range of price elasticities of supply.

Elasticity of supply	Elasticity of demand	ΔP		ΔS		
		%	$ (2006)	%	Q (MMcf)	# wells*
0.50	0.1	–0.36%	–$0.02	0.22%	3,520	91
0.83	0.1	–0.39%	–$0.02	0.36%	5,870	152
1.25	0.1	–0.41%	–$0.03	0.55%	8,810	228

* based on average production per well in 2006

Requiring the incorporation of low-bleed pneumatic systems on new wells would not add significantly to new-well costs. As production from older wells falls, and as the oldest wells are shut in, the introduction of new wells so equipped could result in a steady decline of total emissions without retrofitting any existing wells. This will be explored in section 3.3.

A 20% reduction in segment emissions, constituting a 12.8% reduction in the New Mexico natural gas industry emissions, would be achieved with the conversion of less than 12,000 devices, or about 0.28 devices per well. Even if a significant number of wells have already converted to low-bleed systems, the conversion of 12,000 devices is still a feasible remediation. The total cost for 12,000 devices is about $1.69M, and the increased revenue ranges from $6.3M to $15,7M at the 2006 price, depending on price elasticity of supply, for a net benefit from $4.6M to $14.0M.

With a discount rate as high as 25%, this remediation is cost-effective for any wellhead price down to $4.57 per Mcf [4] or if recovered emissions are as low as 74% of the GasSTAR estimate of 194 Mcf per device per year.

A more in-depth analysis of the production segment is presented in section 3. The analysis there is by no means exhaustive, one of the major limitations being the paucity of data on actual wellhead production and emission volumes. Any remediation effort would have to address this as a first step. Thorough sensitivity analysis is only possible with detailed data on wellhead production and emissions.

2.2 Natural Gas Processing

The processing segment typically includes gathering, which involves transporting raw natural gas and any separated liquids from wellheads to processing facilities by midstream pipelines. The typical composition of raw natural gas is shown in Table 5. The processing segment separates the various hydrocarbon gases – primarily ethane, propane, butane, and various pentanes – from other gases, such as water vapor, carbon dioxide, hydrogen sulfide, and atmospheric gases like nitrogen and helium[6]. The non-methane gases are compressed into liquids and distributed by truck. Similarly, some of the methane may also be compressed and sold as liquefied natural gas (LNG), which is distributed either by truck or by pipeline. Hydrocarbon gases occurring in non-economic quantities may be burned (flared). In New Mexico, non-hydrocarbon gases (water vapor, nitrogen, noble gases, and carbon dioxide) are typically vented to the atmosphere. In some other states, the carbon dioxide is compressed and piped to production areas to be injected into wells for enhanced recovery, but inexpensive carbon dioxide from the Bravo Dome CO_2 wells makes this non-economic[7]. Natural gas going into the processing segment is called *wet*, while natural gas after processing is called *dry*.

Table 5 – Composition of raw natural gas after separation of liquid petroleum (oil).

Typical Composition of Natural Gas		
Methane	CH_4	70-90%
Ethane	C_2H_6	0-20%
Propane	C_3H_8	
Butane	C_4H_{10}	
Carbon Dioxide	CO_2	0-8%
Oxygen	O_2	0-0.2%
Nitrogen	N_2	0-5%
Hydrogen sulfide	H_2S	0-5%
Rare gases	A, He, Ne, Xe	trace

Source: (NGSA-Composition)

There were 25 natural gas processing plants in New Mexico in 2004 (EIA-Processors). The New Mexico Environment Division lists 25 processing plants and three refineries in April 2007 (NMED-Plants).

2.2.1 Sources of greenhouse gases from the processing segment

Processing segment methane emissions account for 15.5% of the New Mexico natural gas industry total and arise from leaks and from venting for maintenance. Direct emissions of carbon dioxide from the processing segment account for 63% of the New Mexico natural gas industry total and arise from venting or burning waste gases and fuel-burning. The most significant contribution to greenhouse gasses is the venting of carbon dioxide in the processing of coal bed methane (46% of New Mexico natural gas industry CO_2 emissions). Total estimated 2006 segment emissions of methane are more than 2200 MMcf (CCAG-H7).

Approximately one-third of natural gas produced in New Mexico is coal bed methane (CCAG-CBM). Carbon dioxide constitutes as much as 18% of the gas from coal bed methane wells in New Mexico (CCAG-Processing). This gas, called *entrained* CO_2, is actually a property of the well, but is attributed to processing because that is where it is separated from the other gases. As mentioned above, this gas could be used for enhanced

[6] This discussion of natural gas processing comes from (NGSA-Processing).
[7] Inferred from statements by the CCAG (CCAG-Processing).

recovery in some oil and gas wells. Additionally, waste carbon dioxide is sometimes stored (sequestered) in depleted wells to prevent its release into the atmosphere. Natural gas processing plants in New Mexico are subject to regulation and taxation. Processing plants tend to be geographically exclusive and therefore operate as monopolies or near-monopolies.

The principal sources of methane emissions nationally from the processing segment are shown in Table 6. Fugitive emissions, the largest source of emitted methane in the segment, may be reduced significantly with directed inspections and maintenance, as discussed in the next section.

Table 6 – Principal sources of methane emissions by the processing segment nationally.

Source	Pct of segment emissions
Fugitive emissions	67
Compressor exhaust	19
Other	14

Source: (EPA/GRI – Executive Summary)

2.2.2 Economics of greenhouse gas reduction: the processing segment

It is anticipated that 77% of processing plant fugitive emissions can be eliminated through directed inspections and maintenance (GasSTAR-DIM), which is a GasSTAR recommended Best Management Practice for this segment (GasSTAR-BMP). Based on the CCAG inventory, this amounts to a reduction of nearly 63 MMcf per year per plant, at an initial cost of a little more than $87,000 and a recurring annual cost of about $65,500 (CCAG-H7).

If processors are able to recover 77% of presently fugitive natural gas, the result would be a reduction of about 8% of the statewide total methane emissions. Putting the entire 63 MMcf recovered from emissions into the supply represents a supply increase of 0.0039%, which is unlikely to affect the market significantly.

There are two revenue streams for New Mexico processors: the value-added in drying natural gas and in the production of natural gas liquids (NGLs). The economic impact of emissions reduction for processors is complicated by several factors:

> **Gas content**. Processing takes raw natural gas, with relatively lower energy density due to contaminants and non-methane hydrocarbons, and produces dry natural gas with high energy density, as well as NGLs such as propane, butane, ethane and liquid natural gas (LNG). Coal bed methane, for example, has a high contaminant volume (mostly CO_2) and low NGL content. The costs of separating the components and disposing of wastes may be greater than the net revenue from NGL sales.

Oil prices. NGLs compete with oil distillates (and bio-fuels, to some extent) in a market subject to broad price fluctuations. Uncertainty in imported oil supply, for example, produces uncertainty in NGL profitability.

Natural gas prices. Ironically, because natural gas is a factor in their production, higher natural gas prices make NGLs less competitive with alternatives.

Contracts. Different types of contracts distribute the revenue and economic risks associated with NGL prices differently between the producer and the processor. This is discussed further in the next paragraph.

While in the long-run energy prices move in parallel, short-run movements between oil prices, NGL prices and natural gas prices can drastically alter the economics of natural gas processing. In terms of risks with regard to NGL prices, the extent to which processors are affected depends on the kinds of contracts they have with producers. There are three classes of processing contracts: fixed-fee (risk assumed by the producer), keep-whole (risk assumed by processor), and percent-of-proceeds (risk is shared), as well as hybrid combinations of these (Starr and Adair 1994).

While reduced emissions represent increased supply through improved technology, to whom that benefit falls also may be complicated by contractual arrangements. The following analysis assumes that both costs and benefits accrue to the processor, but different contracts may distribute either between the producer and the processor. Ultimately, although contracts may present different levels of stickiness, processors, being geographic monopolies, will maximize monopoly rents (profits) in the long run. Typically this means that cost increases are passed on to either producers or consumers.

Margins for natural gas processing have averaged $0.40 per Mcf historically, and have been trending toward $0.80 per Mcf (Baker & O'Brien 2006). If a directed inspections and maintenance (DI&M) program is begun in the first year and gas savings are seen in the second and subsequent years, the second year's savings amount to nearly $388,000 at the 2006 wellhead price[8].

Amortizing the initial cost over ten years with a 5% discount rate, there is an annual net gain from emissions reduction in processing of about $308,000 per plant at the 2006 wellhead price, or about $7.7M for all 25 plants. The annual net gain represents an increase in the margin of about half a cent, or 0.07%. Even if this saving is passed on in its entirety to either producers or consumers, it is unlikely to affect the market significantly. The total methane emission reduction is 1569 MMcf, or about 71% of the segment total.

With a discount rate as high as 25%, this remediation is cost-effective for any wellhead price down to $3.12 per Mcf or if recovered emissions are as low as 50% of the GasSTAR estimate of 63 MMcf per plant per year.

Natural gas processors operate in two disparate markets: the market for drying natural gas, and the market for natural gas liquids. Some may even participate in a third market for carbon dioxide. Because of the complexity of the processing segment and small number of plants in New Mexico, it is recommended that analysis be conducted on each

[8] This assumes that gas is recovered before value-added processing.

of the 25 plants individually. Actual sensitivity to natural gas price fluctuations can only be determined with more data representative producer characteristics.

2.3 Natural Gas Transmission

Transmission in the natural gas industry means pipelines. Transmission pipelines take dry natural gas from processing plants either out of state or to in-state distribution points.

In addition to pipelines owned by midstream processors, there are five major pipeline operators in New Mexico: Transwestern Pipeline Company, El Paso Natural Gas Company, Public Service Company of New Mexico (PNM), Southern Trails Pipeline Company, and TransColorado Gas Transmission Company (EIA-Pipelines). There are 10375 miles of pipeline and 62 compressor stations in New Mexico (CCAG-H7). Transmission firms are considered common carriers (pursuant FERC Order 636, as well as subsequent orders) and may or may not be subject to market powers.

2.3.1 Sources of greenhouse gases from the transmission segment

Methane emissions from the transmission segment account for 15.5% of New Mexico natural gas industry totals, and are due to leaks and maintenance venting of compressors in addition to leaks in the pipes. Carbon dioxide emissions, accounting for 20% of the New Mexico natural gas industry total, are due to fuel-burning. Total estimated 2006 segment emissions of methane are almost 2118 MMcf.

The principal sources of methane emissions nationally from the transmission and storage segment are shown in Table 7. The EPA/GRI report does not distinguish between transmission and storage, and storage is not a consideration in New Mexico, so this study assumes that the overall averages apply to transmission alone. Fugitive emissions, the largest source of emitted methane in the segment, may be reduced significantly with directed inspections and maintenance (DI&M), a GasSTAR Best Management Practice recommendation for transmission (GasSTAR-BMP).

Table 7 – Principal sources of methane emissions by the transmission and storage segment nationally.

Source	Pct of segment emissions
Fugitive emissions	58
Blow and purge	16
Pneumatic devices	12
Compressor exhaust	10
Other	4

Source: (EPA/GRI – Executive Summary)

2.3.2 Economics of greenhouse gas reduction: the transmission segment

There are three general areas of reduction: stepped up inspection and maintenance, upgraded compressors, and modified cleaning and maintenance procedures (GasSTAR-

T&P). As with the processing segment, pipelines are subject to limited market pressure and are government regulated, so that government mandated expenses can be incorporated directly into costs without market distortion. El Paso Corporation has identified three process improvements as having "the highest viability for reducing emissions from the transmission industry": composite wraps for non-leak pipeline repairs, pumping down line pressure before maintenance, and using hot taps in service connections[9]. They conclude that "15 - 25% seems to be a reasonable reduction opportunity assuming the baseline is derived from the corresponding GRI factor."

A DI&M program for transmission compressor stations could reduce emissions by more than 29 MMcf per year per station at an initial cost of almost $30,000 per station and an ongoing cost of about $24,500 per station per year (CCAG-H7). For all 62 transmission compressor stations in New Mexico, this amounts to a reduction of a little more than 1800 MMcf per year, or about 86% of total segment emissions. Amortizing the initial cost over ten years, the total cost is more than $27,000 per compressor per year, for a total cost of almost $1.7M for all 62 compressors. The captured emissions represent a benefit of more than $12.4M at the 2006 city gate price of $6.82 (EIA-Price), for a net benefit of $10.7M, or $173k per compressor.

With a discount rate as high as 25%, this remediation is cost-effective for any city gate price down to $2.28 per Mcf or if recovered emissions are as low as 33% of the GasSTAR estimate of 29 MMcf per compressor per year.

As with the processing segment, because of the small number of pipeline firms, it is recommended that analysis be conducted at the firm level. Sensitivity to natural gas price fluctuations is only possible with a more detailed picture of representative firms.

2.4 Natural Gas Distribution

Distribution firms take natural gas from high volume, high pressure transmission pipelines to low pressure users. Many of these firms are municipalities. New Mexico being a net exporter of natural gas, distribution volume is a small fraction of production.

Distribution entities in New Mexico operate 8977 miles of main pipelines, 4944 miles of service pipelines, 340 metering stations, and 431 pressure regulation stations (CCAG-H7). In 2006, consumption by residential, commercial, and industrial users, including power stations, was 128,028 MMcf (EIA-Consumption), or 7.5% of total production. There were 552,701 New Mexico natural gas customers in 2004 (EIA-Consumption).

2.4.1 Sources of greenhouse gases from the distribution segment

Distribution pipelines are subject to leaks and maintenance venting, as well as leakage and waste by end users, contributing 5% of the New Mexico natural gas industry total. The segment is not a significant contributor to direct carbon dioxide emissions. Total estimated 2006 segment emissions of methane are almost 751 MMcf (CCAG-H7).

The principal sources of methane emissions nationally from the distribution segment are shown in Table 8. Underground leaks, the largest source of emitted methane in the segment, are distributed over 13,921 miles of distribution lines, under various

[9] Naomi Cortez, Western PL Environmental Dept., El Paso Corporation. Email on 29 November 2007.

jurisdictions, making it a difficult remediation to assess. The second largest source of methane emissions are distribution meters and pressure regulating stations. DI&M programs at gate stations and surface facilities are a GasSTAR recommended Best Management Practice for this segment (GasSTAR-BMP), and will be discussed in the next section.

Table 8 – Principal sources of methane emissions by the distribution segment nationally.

Source	Pct of segment emissions
Underground pipeline leaks	54
Meter and pressure regulating stations	35
Customer meters	8
Other	3

Source: (EPA/GRI – Executive Summary)

2.4.2 Economics of greenhouse gas reduction: the distribution segment

Because distribution systems are either publicly operated, or are monopolies which are regulated for public benefit, it is appropriate that economic analysis of the distribution segment be done from the consumer point of view. New Mexico annual natural gas consumption is 128,028 MMcf (EIA-Consumption). The benefit of recovering all methane emissions amounts to $9.26 per customer per year at the 2006 city-gate price of $6.82 (EIA-Price). To break even, costs would have to be a maximum of $200 per mile for distribution lines, $2300 per station for surface facilities, and $0.75 per meter for customer meters. Distribution line inspection and monitoring is an expensive undertaking, especially for low-density municipalities. It is unlikely that customer meter inspection and replacement could be undertaken for less than a dollar per meter. At the level of this study, directed inspection and monitoring (DI&M) for meter and pressure regulating stations is the only clearly cost-effective remediation available to the distribution.

A DI&M program for distribution surface facilities could reduce emissions by 105 Mcf per year per station at an initial cost of $210 per station and an ongoing cost of $157 per station per year (CCAG-H7). For all 771 distribution metering and pressure regulation stations in New Mexico, this amounts to a reduction of nearly 81 MMcf annually, or about 11% of distribution emissions. Amortizing the initial cost over ten years, the total cost is $191 per station per year, for a total cost of less than $142,000 for all 771 stations. The captured emissions represent a benefit of $552,000 at the 2006 city gate price, for a net benefit of almost $405,000, or $0.73 per customer per year.

With a discount rate as high as 25%, this remediation is cost-effective for any city gate price down to $4.47 per Mcf or if recovered emissions are as low as 67% of the GasSTAR estimate of 105 Mcf per station per year.

Although further analysis of the distribution segment would be instructive, it is, at present, the least significant source of greenhouse gases, is highly heterogeneous, and impacts the economy in complex direct and indirect ways.

2.5 Economics of greenhouse gas reduction: summary

Table 9 summarizes the emission reduction remediations reviewed in the preceding sections. Inasmuch as the reductions total to nearly 42% of 2006 levels, the 20% goal is clearly attainable even without complete or across-the-board participation or compliance.

Table 9 – Summary of methane emission remediations reviewed in this section

Segment	Remediation	Reduction			Benefit (Cost)
		MMcf	% segment total	% industry total	
Production	pneumatic devices	2298	20	12.8	$4.6M to $14M
Processing	DI&M	1569	71	11.4	$7.7M
Transmission	DI&M	1800	86	17.2	$10.7M
Distribution	DI&M	81	11	0.55	$147k
Total		5748		41.95	$25M to $36M

The largest contributor to emissions is the production segment, which is evaluated in more detail in the following section.

3.0 Economic analysis of the production segment

Of the four general segments in the natural gas industry, production is the greatest contributor to methane emissions, and the only segment subject to nearly-full market pressures of competition. Thus, while there exist the greatest opportunities for methane emissions reductions, there are also the greatest economic risks. As discussed in section 2.1.2, increased costs can lead to reduced production which, in turn, leads to higher prices. Yet this very market power implies that firms are earning rents (additional profits) from their market power. The question, from an economic perspective, is how much additional cost can be absorbed by natural gas producers before the least productive are forced out of the market? From this can be inferred the economic impact of emission-reduction regulations and project the appropriate levels of government subsides, tax incentives, and fines for non-compliance. Additionally, the size and worth of markets for emission reduction credits or emission permits can be projected. These will inform any decision regarding the appropriate means for affecting emission reduction goals.

At the base of the discussion in the previous paragraph is the notion that representative cost functions[10] for New Mexico natural gas producers are known. There are likely to be multiple cost functions because different cost structures can result from differences in practices and differences in well characteristics, age, and gas properties. Cost structures can vary between firms, fields, and even wells within a field.[11]

The procedural and political complications of collecting the necessary data make it unlikely that disaggregated cost functions can be empirically estimated within the timeframe required. Even anecdotal evidence would be illustrative, but efforts in the course of this study to meet with producers were almost entirely unsuccessful. The three discussions that came out of the only meeting that occurred illustrated, more than anything else, a deep distrust of any regulatory effort or agency.

A second-best solution, then, is to construct a reasonable cost function for the New Mexico natural gas industry based on the best available information. The Energy Information Agency (EIA) collects gas well cost data that can aid in this endeavor. Unfortunately, the EIA data are provided by geographic region and New Mexico straddles two major EIA reporting regions – the San Juan and Raton Basins are incorporated into the Rocky Mountain Region, whereas the Permian Basin is included in the West Texas Region. For the purpose of this study, cost data from the West Texas Region is used to develop a cost model for the New Mexico natural gas industry. The development and analysis of the cost model is discussed in section 3.1. This model is used in section 0 with production and price forecasts through 2020. From these it will be possible in section 3.3 to examine emission reductions arising from the aging and attrition of older wells, increased emissions from new wells, and what overall level of emission reductions existing wells will have to achieve between now and 2020. Finally, section 0 will present various outcomes.

3.1 New Mexico natural gas production cost model

The only readily available per-well cost data (EIA-Cost) reports average well costs as a function of flow rate and well depth. Costs are modeled as a function of flow rate, production in Mcf per year, the depth of production (in feet), and year (to account for external economic impacts). That is

$$C\left(rate, depth\right) = \alpha \bullet rate^{\beta_{rate}} \bullet depth^{\beta_{depth}}$$

The cost function is estimated using the EIA data. Consistent with (Chermak and Patrick 1995), a Cobb-Douglas single-well cost model is developed[12]. The Cobb-Douglas specification allows for a multiplicative relationship of the independent variables, in this case, production and depth. This specification requires all independent variables be non-negative. This allows for differences in costs due to the depth of the well (deeper wells

[10] A cost function gives the cost of production based on the amount produced.

[11] For more information concerning the disaggregation of costs see, for example, (Chermak and Patrick 1995).

[12] The Chermak Patrick model was based on individual well data and included more characteristics than are available from the EIA data, such as monthly flow rate, remaining reserves, and the age of the well

are more expensive) and higher flow rates may be more expensive (heavier equipment, more maintenance).

The form of the log-linear econometric regression is

$$\ln C\left(rate, depth\right) = \ln\alpha + \beta_{rate}\ln rate + \beta_{depth}\ln depth + \sum_{i=1}^{18}\delta_{i,year}$$

The multiplicative nature of the costs also introduces multiplicative heteroskedasticity (Greene 2002), exacerbated in this case because the flow rates and depths are averaged over only a few categories, as shown in Table 10. The data for this model (Tables H6 through H10) are for the West Texas Region, which includes New Mexico's Permian Basin wells.

Table 10 – Depth and flow rate data categories for which EIA data are available.

Table	Well Depth (1,000 ft)	Production Rate (Mcf per day)				
H6	2	50	250			
H7	4	50	250			
H8	8	50	250	500		
H9	12		250	500	1,000	
H10	16			500	1,000	5,000

The data were inflation adjusted to 2006 dollars using (BEA-Deflators). The results of a maximum-likelihood estimation which includes correction for multiplicative-heteroskedasticity are shown in Table 11.

Table 11 – Cost model regression results

	Model	**Variance**
Independent variable	**Coefficient (Std. error)**	**Coefficient (Std. error)**
Constant	4.422661 (.0471053)*	-17.84486 (.128068)*
ln (rate)	.1197363 (.0031704)*	-2.891497 (.128068)*
ln (depth)	.5023441 (.0040557)*	5.469812 (.1714364)*
All year dummy variables *		

* significant to 1%

The model explains virtually all of the variation in the data and all parameters are significant[13]. Thus, the cost model is

$$C\left(rate, depth\right) = 83.3 rate^{0.120} depth^{0.502}$$

This model is applied to the New Mexico Oil Conservation Division all-wells database (OCD 2007). A scatter plot of estimated costs, eliminating zero cost estimates, is shown

[13] Parameters are also fit for data-dependent variance terms. This is a product of the correction for multiplicative heteroskedasticity.

in Figure 5. To expose greater detail, Figure 6 eliminates average costs above the 2005 New Mexico average wellhead price of $7.51 (EIA-2005) as well as the highest quintile in production, which includes a few extremely productive wells. Ultimately, these data can be used to infer a supply curve, as shown in Figure 7.

3.2 Natural gas production forecast scenarios

Forecasting is easy: production will increase, decrease, or stay the same. Production from a natural gas well will decrease naturally over time until it becomes economically nonviable. As long as sources (reserves) exist, new wells will be brought into production. Whether these add up to increased, decreased, or unchanged total production depends on:

- The market price for natural gas
- The extent of natural gas reserves
- How quickly the new wells are brought into production (completions)
- The flow rates of the new wells

3.2.1 Natural gas price forecasts

The Consensus Forecast of natural gas prices by the New Mexico Legislative Finance Committee (LFC) are shown in Table 12 (Schardin and Francis, 2007, p. 6.), along with Congressional Budget Office inflation forecasts (CBO 2007). Between 2008 and 2012, effective (inflation adjusted) natural gas prices are expected to decrease. Historically, levels of production follow prices closely, so New Mexico natural gas production is expected to decrease over this time. The LFC forecasts a two percent annual decrease in natural gas production in New Mexico over this period. National natural gas wellhead prices are forecast to decline an additional 4.5% between 2012 and 2020 (EIA-Forecast). This supports a continued decline in natural gas production in New Mexico through 2020.

Table 12 –Legislative Finance Committee natural gas price projections for December 2007.

Year	Average NM wellhead price*[1]	Forecast change*[2]	Inflation*[3]
FY08	$6.46	-1.67%	2.32%
FY09	$6.56	1.55%	2.23%
FY10	$6.59	0.46%	2.20%
FY11	$6.52	-1.06%	2.20%
FY12	$6.52	0.00%	2.20%

*[1] Source (Schardin & Francis, 2007 – spreadsheet)
*[2] Starting with FY07 actual of $6.57 (ibid)
*[3] Congressional Budget Office CPI Forecast (CBO)

To forecast the effect of price change on the number of natural gas wells in New Mexico, it is necessary first to compute the gas-price elasticity of new-well starts. Historical data are available for active drilling rigs, which is a reasonable proxy given that 92% of the state's 43,248 active wells in 2006 produced natural gas. Monthly average rig counts from January 1990 through September 2007 (Baker Hughes) were ordinary least squares (OLS) regressed against lagged rig count and average New Mexico wellhead prices during the same period (EIA-Price).

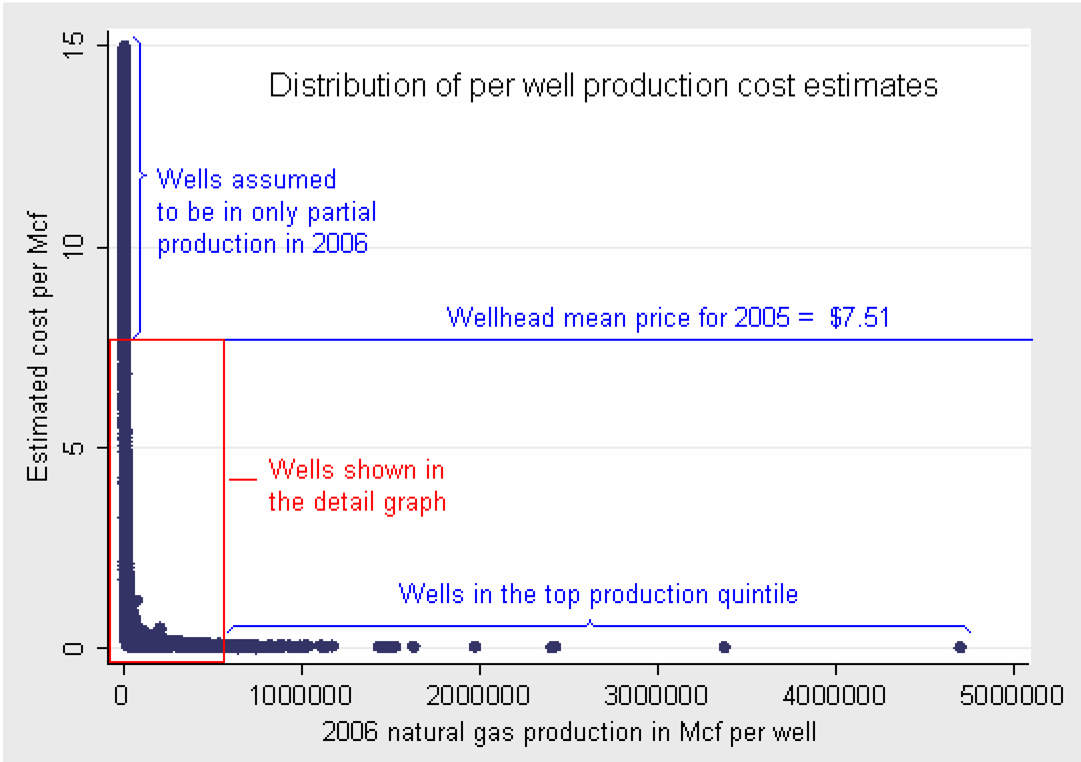

Figure 5 --Cost model applied to OCD data

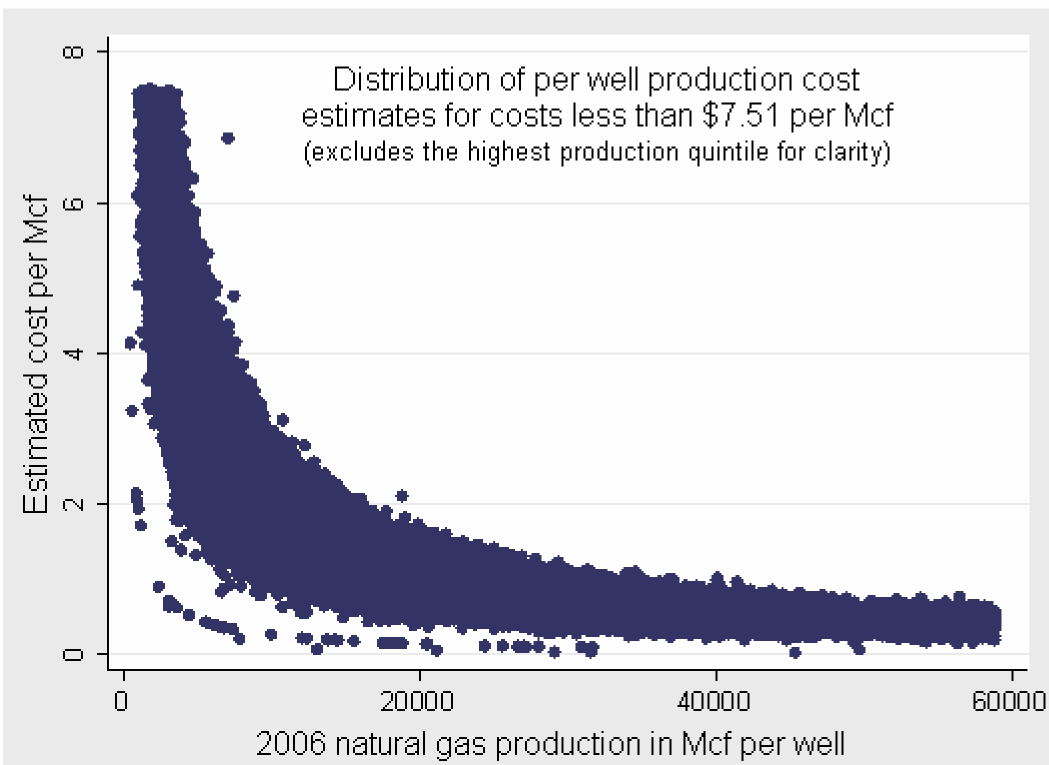

Figure 6 – Detail of cost model applied to OCD data

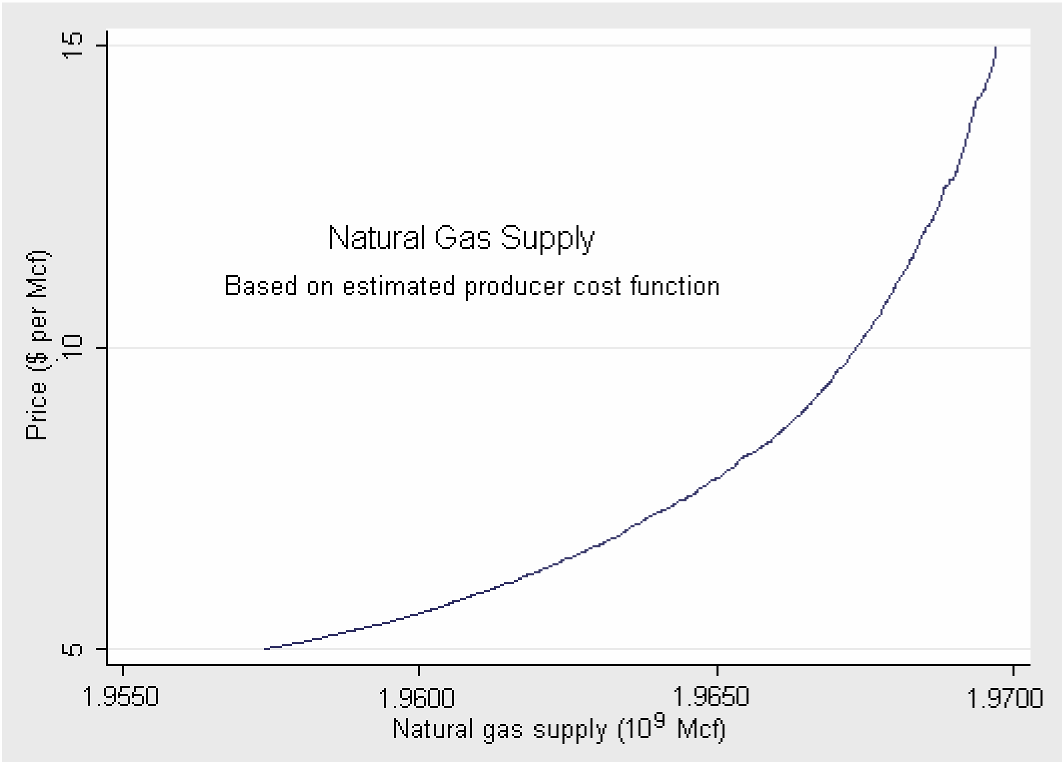

Figure 7 – Inferred supply function from cost estimate

That is, the AR(1) model

$$\ln rigcount_t = \ln \alpha + \beta \ln price_t + \gamma rigcount_{t-1}$$

Results are shown in Table 13. All coefficients are significant at the 1% level, and 89% of variations in the data are explained by the model. Note the near-unit value for the previous year variable. A Dickey-Fuller test confirms that this is a unit root and vector-error-correction regression reveals that rig count is essentially a random walk variable.

Table 13 – Regression results for price elasticity of rig count

Independent variable	**Coefficient (Std. error)**
Constant	.3638731 (.1009478)
ln (price)	.0639056 (.0183826)
previous year ln (rig count)	.8896625 (.1009478)

Given this outcome, there is no indication that changes in natural gas prices will affect the rate of well drilling, so that the number of new producing wells each year will likely remain fairly constant[14].

[14] Decreasing production with a constant net increase in the number of wells can be explained in that most new wells are *in fill* wells – wells drilled into existing fields, essentially between existing wells. Production levels fall as the field is depleted, even as the number of wells depleting it increases.

3.3 Methane emission reductions through new well technology, old well attrition

The economics of designing and building new wells to emit less methane is somewhat more straightforward than the economics of retrofitting existing wells. When emission control costs are included in the initial cost proposal, wells that cannot be made emission-level compliant won't be drilled in the first place. With the addition of new, cleaner wells and the plugging of old, non-producing wells, the overall level of methane emissions may be reduced even before retrofitting existing wells.

Between 2001 and 2005 there was an average annual net increase in producing natural gas wells of 1242 (EIA-New) and an average of 258 gas wells were plugged annually during those years (OCD 2007), meaning that an average of 1500 new gas wells came into production annually during that time. The trend in natural gas wells is shown in Figure 8. In the historical EIA data, or OCD data before 2005, it's not possible to determine if an oil well also produced natural gas, so these figures include gas wells only. Overall, 36% of gas-producing wells in New Mexico are oil wells, so the actual trend in Figure 8 may be about 55% higher.

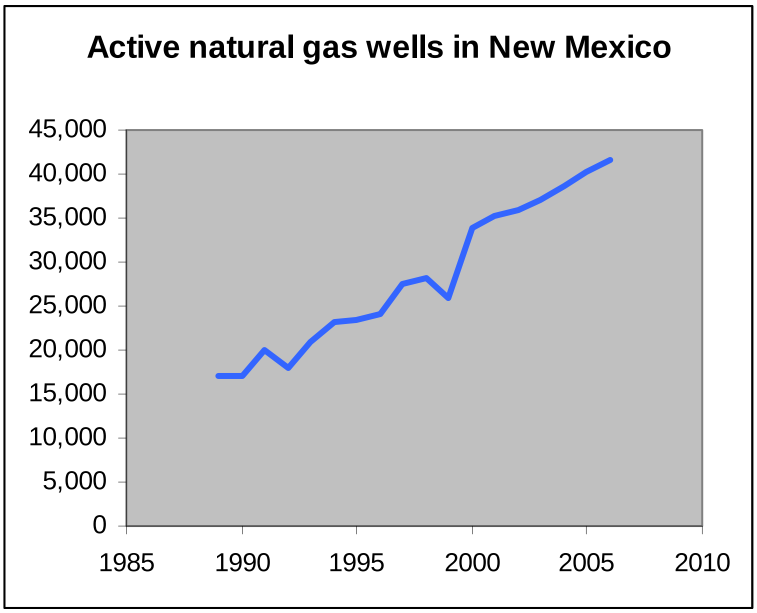

Figure 8 – Active natural gas wells in New Mexico, 1988 – 2006. Source (EIA-New).

The average lifetime of all plugged gas wells in the OCD database is 18.7 years, and the average lifetime of all plugged oil wells is 14.7 years. The weighted average, assuming 36% of gas-producing wells are oil wells, is 17.2 years. Figure 9 shows the distribution of ages of gas-producing wells in 2006. Natural gas wells in the OCD database are retired at a mean rate of 0.737% per year.

Assume that older wells emit the 2006 average of 276 Mcf of methane per year and that all wells coming on line beginning 2008 emit at the lower average rate of 38 Mcf per year[15]. The first three columns of Table 14 shows the retirement schedule for wells producing in 2006 based on this rate. Shutting in these wells eliminates an average of 276 Mcf per year of methane emissions or a total of 854 MMcf per year. During the same time, an average of 1500 new gas wells will be coming into production each year. Figure 8 shows the trend in the number of active wells over the past 20 years. If each of them emits 38 Mcf per year, the increase in emissions will be about 684 MMcf per year for the 18,000 added wells. These new wells are also subject to the mean retirement rate and are shown in the last two columns of Table 14. The shutting in of these wells eliminates an average of 82 Mcf per year of methane emissions for an additional reduction of 36 MMcf per year. The net impact is a reduction of 207 MMcf per year, or nearly 2.3% of 2006 segment emissions. This amounts to a reduction in total natural gas industry emissions of nearly 1.5%.

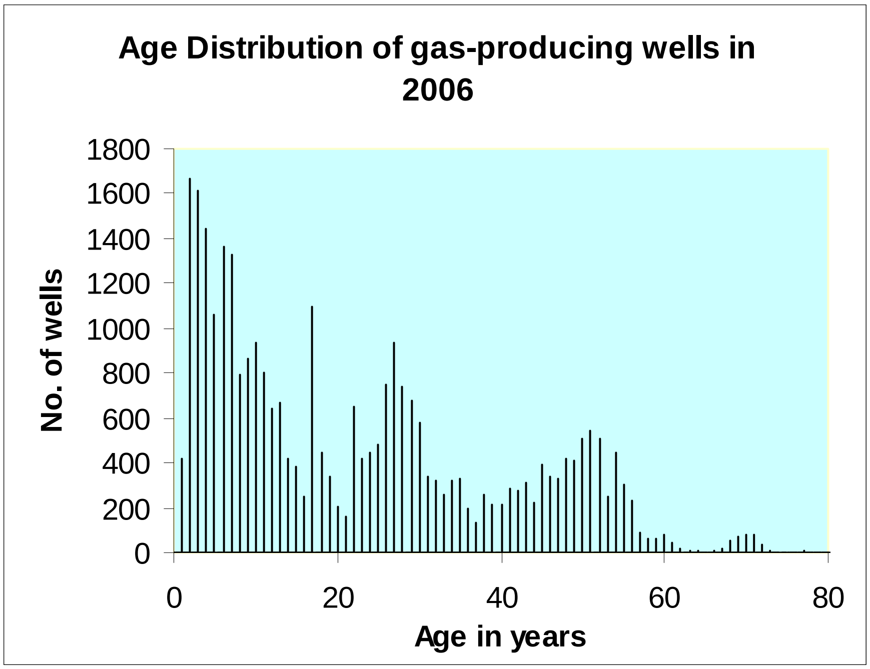

Figure 9 – Age distribution of gas-producing wells in 2006. Source (OCD 2007).

In addition to natural attrition due to age, there is an additional economic consideration with regard to the aging of wells. The economic viability of wells with added emission-reduction costs was discussed in section 2.1.2. Of interest is how that computation is affected by the aging of the well.

Figure 10 shows the estimated cost function developed in section 3.1 as a function of production level for five different well depths. At its simplest, the aging of a well is simply movement to the left along a line parallel to those shown. What is not evident from this graph is the point at which revenue falls below cost.

[15] This is the equivalent eliminating 1.325 high-bleed control systems per well (CCAG-H7).

Table 14 – Emission reductions through attrition 2007 - 2020

Year	No. of pre-2008 wells shut in	Emission reduction through attrition (Mcf/year)	No. of post-2008 wells shut in	Emission reduction through attrition (Mcf/year)
2008	267	73,692	22	837
2009	263	72,588	33	1,251
2010	263	72,588	44	1,662
2011	263	72,588	54	2,070
2012	263	72,588	65	2,475
2013	263	72,588	76	2,876
2014	261	72,036	86	3,275
2015	259	71,484	97	3,671
2016	253	69,828	107	4,064
2017	248	68,448	117	4,454
2018	247	68,172	127	4,842
2019	245	67,620	138	5,226
Total	3,095	854,220	966	36,704

Source: (OCD 2007)

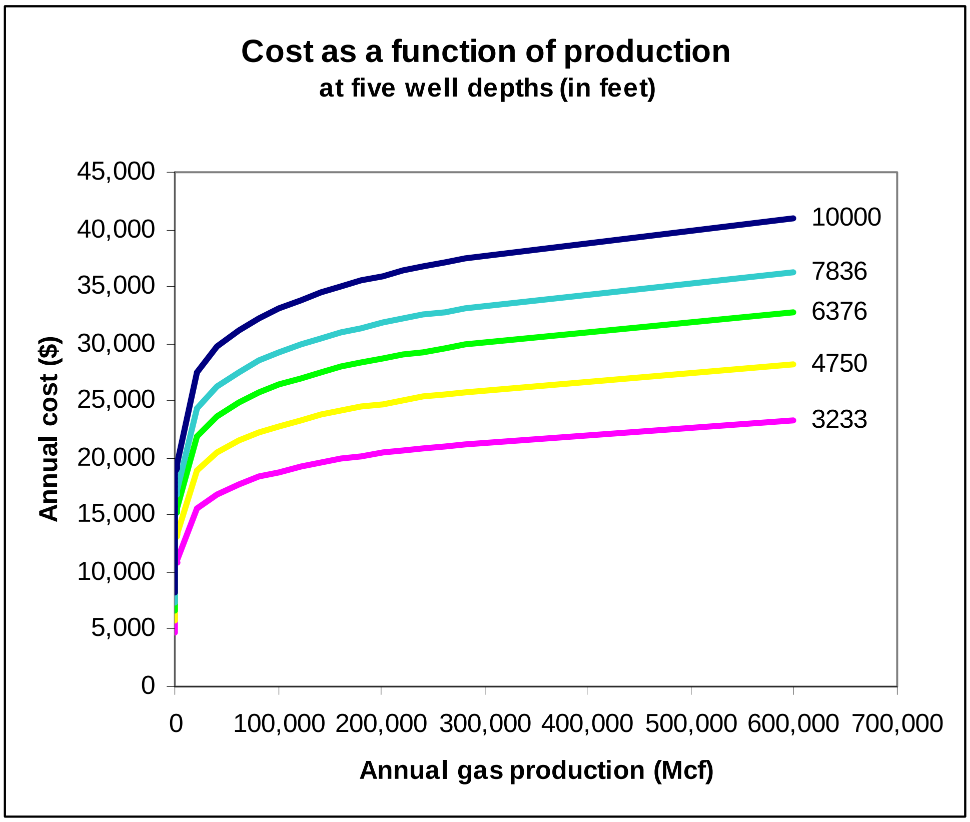

Figure 10 – The estimated cost function as a function of production level at five depths.

Table 15 and Table 16 show various cost statistics for wells grouped by cost quintile and by production level quintile. Table 15 includes a table of median well age per quintile, and Table 16 includes difference between mean and median. Note here that the low production/high marginal cost group (upper right corner) has a mean of $6.89, well above the 2006 wellhead price of $6.18, but a median of about $6.00. This indicates that, although some wells in this group operate at a loss, more than half of them operate at break-even or better. The bottom table in Table 16 illustrates those groups that are skewed below the mean (pink cells) and those that are skewed above the mean (blue cells).

Over time, a given will move up the tables to lower production levels. As Figure 10 implies, marginal cost will not change significantly until the well is very close to end of life. The sparseness of the low production level/low marginal cost cells (lower left) in Table 16 implies that wells are shut in before they reach these levels.

Presumably new wells come into production in the lower rows of the table. Increased emission-reduction costs will move them further to the right, however. The quarter of a cent increases discussed in section 2.1.2 are not likely to move them by much – there's a roughly 50% increase in the mean marginal cost going across the table.

Thus, analysis of the cost model is consistent with the finding in section 2.1.2 and earlier in this section that increased emission-reduction costs will impact a few very-low-production very-high-marginal-cost wells, but otherwise the production segment can withstand the added costs of retrofitting or replacing high-bleed devices. With the strong correlation between high production rate (observable) and low marginal cost (non-observable), one regulatory approach may be to require low-bleed replacement for high-production wells for which, presumably, high revenues ensure its cost effectiveness.

3.4 Combined strategies for methane emission reductions

The decision on the best combined strategies to reach the 2020 goal will have to be based on a number of broad and possibly conflicting objectives. These objectives will have to consider:

1) impact on existing wells – any change in industry cost structures will have the greatest impact on older, low productivity wells. Policy-makers will have to weigh the economic costs of causing some wells to shut in a little earlier than planned against the benefits of reduced emissions, and possibly a reallocation of resources to newer, cleaner, more productive technologies.
2) impact on new wells – any program that shifts the advantage from older wells to new wells may have the consequence of over-stimulating new well development, consequently lowering the profitability of new wells.
3) impact on processors – policy-makers will have to consider carefully processors' contract portfolios, in particular the flexibility and duration of existing contracts, as well as existing regulatory burdens.
4) impact on pipelines – pipelines, like processors, will be subject to contractual and regulatory limitations.
5) impact on distributors – the distribution segment will be slow to change for myriad social and political reasons. Policy-makers will have to take an especially long view with regard to distribution entities.
6) impact to State tax revenues – the natural gas industry is a major source of revenue for the State of New Mexico. Many strategies, especially those involving

incentives, may be at odds with preserving the State's revenue stream. These things will have to be balanced carefully.

A follow-on study to this assessment could examine each of these strategies in detail.

4.0 Incentives, market solutions, and regulatory opportunities

The shortage of sound data is the biggest limitation to designing effective government incentives, market incentives, or regulatory measures. Without reasonable incentive and regulation packages, it is impossible to recommend among them. One recommendation to come out of this study is the urging to establish collection of consistent and timely data on methane production and emission levels as a function of well age, technology, region and type (gas versus oil). The reluctance of natural gas producers to provide information for this study may portend limited success for voluntary disclosure programs.

4.1 NMED identified emission reduction programs

Appendix F is a summary of implementation and enforcement methods prepared by Dominique Gomez, a Fellow in Public Policy with NMED in the summer of 2007. The following paragraphs address the economic impact of each of these measures.

4.1.1 Revolving loan fund

This isn't an incentive to compliance unless costs and benefits are very similar. The evidence that the natural gas industry has not already implemented apparently profit-enhancing programs suggests that costs and benefits are perceived as being quite far apart. For those firms that view costs and benefits as being very close, loans can shift the balance in favor of compliance. While many of the identified emission reduction opportunities (CCAG-H7) are fairly inexpensive, some (replacing gas-fueled compressors with electric, for example) tie up significant amounts of capital. A revolving loan fund (RLF) lowers the opportunity cost of tying up that capital. An incentive would either reduce the total opportunity cost of compliance below other capital alternatives (by providing a tax break, for example), or raise the opportunity cost of the alternatives (by imposing a fine, for example). There is a regulatory aspect to loans for emission reduction: ensuring that the funds are used as intended, and that their use actually achieves lower levels of emissions. This is not a good solution for measures incurring large ongoing (operations and maintenance) costs.

4.1.2 Subsidies for new technology

Again, this is not an incentive to compliance but rather a means to comply. See the discussion in section 4.1.1. For a subsidy, the opportunity cost of compliance is even lower than with a loan (assuming the subsidy is a grant and not a loan), but it doesn't provide a means for making compliance the lowest opportunity cost alternative. Additionally, as with loans, there is limited relief for large ongoing costs, and there will be significant enforcement costs.

Table 15 – Marginal cost statistics and well age by production and cost quintiles

Number of wells

		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**	0	6	3	761	5683
	2	10	21	982	4670	770
	3	32	995	4404	1022	0
	4	871	4519	1063	0	0
	5	5540	912	1	0	0

Mean marginal cost

		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**	.	0.63145	1.198442	2.577402	6.890304
	2	0.274526	0.682274	1.182961	2.091777	3.544154
	3	0.268195	0.625512	1.061744	1.605991	
	4	0.321454	0.574483	0.863363		
	5	0.213177	0.455666	1.173159		

Marginal cost std. dev.

		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**		0.065464	0.268375	0.334415	3.075839
	2	0.107603	0.085221	0.161426	0.423944	0.430833
	3	0.123974	0.091811	0.173461	0.169843	
	4	0.058091	0.098101	0.094335		
	5	0.107385	0.049914			

Ratio std. dev. to mean

		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**		0.103672	0.223937	0.129749	0.446401
	2	0.391961	0.124907	0.136459	0.202672	0.121562
	3	0.462252	0.146777	0.163374	0.105756	
	4	0.180713	0.170764	0.109264		
	5	0.503734	0.109541			

Mean well age in years

		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**		2.90	17.50	27.60	25.17
	2	1.83	12.84	24.82	25.35	18.85
	3	9.60	21.77	25.62	20.31	
	4	17.85	24.23	21.25		
	5	13.06	15.24	1.24		

Table 16 – Marginal cost extrema, median, and skew

Minimum marginal cost						
		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**	.	0.515909	0.890981	1.495813	3.054356
	2	0.059372	0.42085	0.764759	1.410666	3.053874
	3	0.038895	0.401952	0.761267	1.411131	.
	4	0.019885	0.400949	0.761339	.	.
	5	0.005615	0.399985	1.173159	.	.
Maximum marginal cost						
		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**	.	0.711778	1.385729	3.04875	15.00135
	2	0.391698	0.75794	1.410557	3.053679	6.855237
	3	0.399025	0.760929	1.410565	2.3977	.
	4	0.399911	0.761239	1.297859	.	.
	5	0.399945	0.656666	1.173159	.	.
Median marginal cost						
		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**	.	0.639648	1.318617	2.641198	5.999467
	2	0.288821	0.711526	1.209508	2.040999	3.432908
	3	0.342215	0.642553	1.046113	1.556177	.
	4	0.330101	0.568829	0.832329	.	.
	5	0.211513	0.442756	1.173159	.	.
Median minus mean						
		marginal cost quintile				
		1	**2**	**3**	**4**	**5**
production level quintile	**1**		0.008198	0.120175	0.063796	-0.89084
	2	0.014296	0.029252	0.026547	-0.05078	-0.11125
	3	0.07402	0.017041	-0.01563	-0.04981	
	4	0.008648	-0.00565	-0.03103		
	5	-0.00166	-0.01291	0		

4.1.3 Carbon tax

A carbon tax may provide the shift necessary to make compliance the lower opportunity cost alternative. However, taxation is a two-edged sword: the temptation is to replace some of the existing taxes on natural gas with an equal carbon tax to lessen the impact of taxation, but long-run reduced emissions lowers the State's tax revenue. Thus, the State has a clear incentive to increase tax rates in the long run, which makes firms apprehensive in the first place.

A related approach is pollution tax credits where reductions in emissions are rewarded with tax credits. If implemented as a one-time credit, it works like loans or subsidies, whereas an ongoing credit works like a negative tax. Ultimately, the public policy purpose of taxation is to transform the external costs (global climate change) into internal costs. While an uncompensated carbon tax accomplishes this, tax credits effectively transfer the external cost to the taxpayers rather than to the generators of the externality.

4.1.4 Cap and trade policies

The cap-and-trade approach to emission control sets an allowance to be distributed among emitters, then allows those who under-emit to trade with those who over-emit.

To implement a cap-and-trade program, the State must:

- Set emission limits (caps) – with all the monitoring and enforcement infrastructure that entails (see section 4.1.7)
- Guarantee property rights for allowances

The rest of the program and its success lie with the marketplace. There is no guarantee that a market will form, or that it will work efficiently. Some natural gas producers in New Mexico have expressed skepticism about a CTA program based on a belief that the State could, and would, capriciously eliminate property rights for allowances.

4.1.5 Transparency requirements

Transparency may work as an incentive in consumer markets, but has little effect in a commodity market where the producers are effectively anonymous

4.1.6 Tax Incentive for Participation in EPA's Gas STAR

Tax credits as incentives are covered in section 4.1.3.

4.1.7 Legislation requiring reduction

As mentioned in section 4.1.4, voluntary programs only work if the State has some teeth behind them. For any program to work, the State will have to set appropriate levels, establish a monitoring program, develop monitoring expertise to enforce both monitoring requirements and compliance levels, and have the ability to punish infractions with enough speed and force as to provide a disincentive for cheating. Federal cap-and-trade programs have been successful in part because all of the infrastructure, best practices, enforcement mechanisms, and enforcement agencies were mature when the programs were introduced (Tietenberg *et al* 1999). In New Mexico, this will take considerable action by both the legislature and the executive. In effect, any program will have to begin with legislation.

5.0 Summary

This assessment shows that at least 20% reduction in methane emissions is economically feasible in the production, processing and transmission segments. A 20% reduction in emissions by the distribution segment are probably feasible, but would require significant coordination with the myriad distribution systems, many of which are publicly owned. 20% of distribution emissions, however, amount to 1.2% of the other segments emissions, so an overall 20% reduction is feasible without the distribution segment.

There are two general results of this analysis.

The first result is that the production segment, being subject to market pressures, cannot escape some transformation as a result of emission-reduction policies. The most likely outcome is the early shutting in of a few hundred near end of life wells. The rest of the production segment can easily bear emission-reduction costs. The production segment is most likely to respond to market-based programs like cap-and-trade after the fallout from initial implementation.

The second result is that the processing, transmission, and distribution segments, being in near-monopoly markets, are able to pass on added emission-reduction costs. These segments also require capital-intensive remediations, making them most likely to take advantage of loans, subsidies, or other fixed-cost offsetting programs.

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