3. Natural Gas Systems

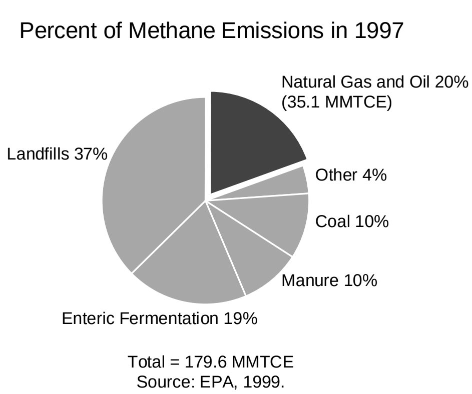
Summary

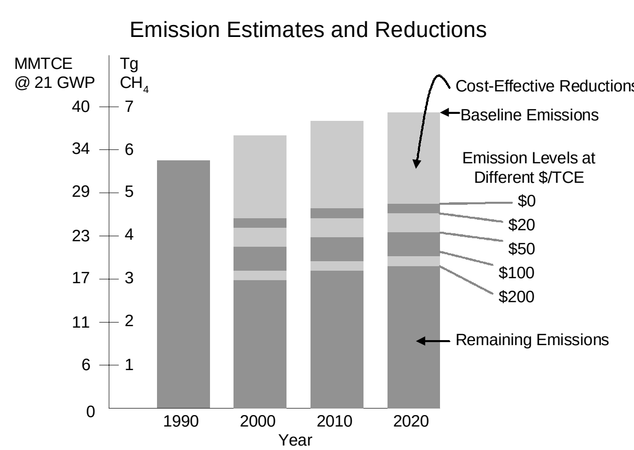
EPA estimates 1997 U.S. methane emissions to be 33.5 MMTCE (5.8 Tg) from natural gas systems and 1.6 MMTCE (0.3 Tg) from oil systems, which together accounted for approximately 20 percent of total U.S. anthropogenic methane emissions (EPA, 1999). In 1997, the U.S. produced 18.9 trillion cubic feet (Tcf) (364 Tg) and consumed 22.0 Tcf (422 Tg) of natural gas (the balance was imported), which is 95 percent methane (EIA, 1999). Natural gas is produced at thousands of gas and oil wells, purified at hundreds of processing plants, transported through a continental network of pipelines, and delivered to millions of customers. Natural gas consumption is divided among industrial (44 percent), residential (25 percent), commercial (16 percent), and electric utility (15 percent) uses (EIA, 1998). Methane is emitted to the atmosphere through leaks and by accidental and deliberate venting of natural gas during normal operations, i.e., production, processing, transmission, and distribution. Because natural gas is often found in conjunction with oil, its production and processing also emits methane.

EPA expects baseline emissions from natural gas systems to grow as natural gas consumption increases. The U.S. Department of Energy anticipates U.S. gas consumption will increase 1.6 percent each year between 1996 and 2020, leading to annual consumption of about 32 Tcf (618 Tg) by 2020. Demand is expected to increase in all sectors, especially from electric utilities (EIA, 1998). However, equipment turn-over along with new and more efficient technologies will result in a methane emission growth rate that is lower than the growth in consumption. EPA estimates that methane emissions from natural gas systems will reach 37.9 MMTCE (6.6 Tg) by 2010, excluding possible Climate Change Action Plan (CCAP) reductions.

CCAP's Natural Gas STAR Program, a voluntary EPA-industry partnership, has identified cost-effective technologies and practices that can reduce methane emissions. In 2010, EPA estimates that up to 10.1 MMTCE (1.8 Tg) of reductions are cost-effective at energy market prices (in 1996 US$) or $0/TCE, as Exhibit 3-1 shows. Methane emissions could be reduced below 1990 emissions of 32.9 MMTCE (5.7 Tg) for natural gas systems if these cost-effective technologies and practices are thoroughly implemented. More reductions could be achieved with the addition of higher carbon equivalent values.

Exhibit 3-1: U.S. Methane Emissions from Natural Gas Systems (MMTCE)





1.0 Methane Emissions from Gas and Oil Systems

This section summarizes the sources of emissions from oil and gas systems and describes EPA's methodology for estimating these emissions. The section also presents EPA's emission estimates and forecast.

1.1 Emission Characteristics

Natural Gas. The natural gas sector is comprised of four major sub-sectors: production, processing, transmission, and distribution. Methane emissions occur during normal operations in all sub-sectors as described in Exhibit 3-2. During production, gas exits wells under very high pressure, often greater than 1,000 pounds per square inch (psi). The gas is routed to dehydrators, where water and other liquids are removed, and then to small-diameter gathering lines for transport to either processing plants or directly into interstate pipelines. Processing plants further purify the gas by removing natural gas liquids, sulfur compounds, particulates, and carbon dioxide. The processed gas, which is about 95 percent methane, is then injected into large-diameter transmission pipelines where it is compressed and transported to distribution companies, often hundreds of miles away. Distribution companies take the high-pressure gas (averaging 300 psi to 600 psi) and reduce the pressure to as low as a few pounds or even ounces per square inch for delivery to homes, businesses, and industry.

From wellhead to end user, the gas moves through hundreds of valves, processing mechanisms, compressors, pipes, pressure-regulating stations and other equipment. Whenever the gas moves through valves and joints under high pressure, methane can escape to the atmosphere. In many instances, gas is vented to the atmosphere as part of normal operations. For example, a major source of vented emissions are pneumatic devices, that operate valves using pressure in the system and bleed small amounts of gas to the atmosphere when valves are opened and closed. Another example of venting is the common industry practice of shutting down a compressor and purging the gas in the compression chamber to the atmosphere.

Oil. Most oil wells produce some natural gas, which is usually dissolved in the crude oil stream. Methane and other volatile hydrocarbon compounds dissolved in oil escape the solution as the oil is processed and stored in

Exhibit 3-2: Sources of Methane Emissions from Oil and Gas Activities (1997)

Industry Sector	Natural Gas Industry Sources of Emissions	Percent of Total and Amount	Crude Oil Industry Sources of Emissions	Percent of Total and Amount
Production	Wellheads, dehydrators, separators, gathering lines, and pneumatic devices	25% 8.4 MMTCE or 1.5 Tg	Wellheads, separators, venting and flaring, other treatment equipment	49% 0.7 MMTCE or 0.13 Tg
Processing	Compressors and compressor seals, piping, pneumatic devices, and processing equipment	12% 4.1 MMTCE or 0.7 Tg	Waste gas streams during refining	2% 0.1 MMTCE or 0.01 Tg
Transmission & Storage	Compressor stations (blowdown vents, compressor packing, seals, valves), pneumatic devices, pipeline maintenance, accidents, injection/withdrawal wells, pneumatic devices, and dehydrators	37% 12.4 MMTCE or 2.2 Tg	Transportation tanker operations, crude oil storage tanks	48% 0.7 MMTCE or 0.13 Tg
Distribution	Gate stations, underground non-plastic piping (cast iron mainly), and third party damage	26% 8.6 MMTCE or 1.5 Tg	Not applicable	
Total		33.5 MMTCE or 5.8 Tg		1.6 MMTCE or 0.27 Tg

Totals may not sum due to independent rounding.
Source: EPA, 1999.

holding tanks before being transported off the well site. Depending on how much gas is associated with the oil, field operators may install equipment to capture and sell much of the gas.

1.2 Emission Estimation Method

The method for estimating emissions from natural gas systems is different from the method for oil systems. These methods are described below.

1.2.1 Natural Gas System Emissions

EPA relies on three types of data to generate the annual methane emission inventory: emission factors, activity factors, and activity factor drivers. These elements are described below:

- **Emission Factors.** Emission factors describe the rate of methane emissions measured or estimated at a piece of equipment or facility during normal operations. The source of the emission factors is a detailed study, *Methane Emissions from the Natural Gas Industry*, sponsored by EPA and the Gas Research Institute (EPA/GRI, 1996). Based on this study, EPA has developed emission factors for about 100 sources within the natural gas industry, e.g., gas well equipment, pipeline compressors and equipment, and system upsets.

- **Activity Factors.** Activity factors are statistics on pieces of equipment or facilities that are associated with given emission factors. Examples include number of wells, miles of pipe of a similar type and operating regime, or hours of operation by compressor type. Activity factors are critical for extrapolating from a limited set of emission measurements at individual pieces of equipment to larger facilities and ultimately to the entire industry. The EPA/GRI study developed activity factors corresponding to the emission factors. Additional sources of activity data are publications from the Energy Information Administration (EIA), American Petroleum Institute (API), American Gas Association (AGA), and others.

- **Activity Factor Drivers.** Activity factor drivers are used to adjust the magnitude of activity factors from year to year consistent with gas market and industry changes in order to update or forecast emission estimates. Examples of drivers include gas sales, miles of distribution main, number of wells, and hours of compressor operations. In some cases, the relationship between activity factor drivers and emission estimates may be indirect. For example, to estimate emissions from glycol dehydrators, EPA first estimates an average number of dehydrators per well. The number of wells, i.e., the activity factor driver, is updated annually and used to update emissions from glycol dehydrators. EPA obtains activity driver data from EIA, API, AGA, and other industry sources.

Appendix III, Exhibits III-1 and III-2 summarize the emission factors, activity factors, and activity factor drivers used in this analysis.

The emission inventory estimate begins with a functional segmentation of the industry and the activities that occur within each segment: production, processing, transmission and storage, and distribution (See Exhibit 3-2). For each segment, EPA estimates emissions by multiplying emission factors (EF) by associated segment-wide activity factors (AF) as shown in this formula:

$$\text{Total emissions} = \text{EF x AF}$$

The multi-volume EPA/GRI report, *Methane Emissions from the Natural Gas Industry*, analyzes emissions from all gas industry segments for the year 1992 and sums these emissions. EPA uses this estimate for the 1992 national estimate. For the period 1990 to 1997, EPA uses the activity factor drivers to adjust the 1992 estimate to reflect annual changes in the industry.

While EPA annually adjusts activity factors to reflect year-to-year changes in the industry, emission factors are treated differently. For the period 1990 to 1995, the emission factors are held constant. However, EPA assumes that a gradual improvement in technology and practices along with equipment replacement will lower emission factors by a total of five percent between 1995 and 2020.

1.2.2 Oil Industry Emissions

The current estimates of methane emissions from the oil industry depend on emission factors and activity factors based on broad categories of activities in the oil industry and not on a detailed, bottom-up approach as used for the natural gas sector estimates. The major oil sector activities are summarized in Exhibit 3-3.

Production Field. Emission factors for oil production are taken from *Anthropogenic Methane Emissions in the United States: Estimates for 1990, Report to Congress* (EPA, 1993). Emission factors are multiplied by updated activity factors (for the portion of oil wells that do not produce associated gas) as reported by API (1997).

Crude Oil Storage. Baseline emissions from crude oil storage are from Tilkicioglu and Winters (1989), who developed emission factor estimates by analyzing a model tank battery facility. These emission factors are applied to published crude oil storage data to estimate total emissions across the industry. Crude oil storage data are obtained from the Department of Energy (EIA, 1991-97).

Refining Waste Gas Streams. Tilkicioglu and Winters estimated national methane emissions from waste gas streams based on measurements at ten refineries. These data were extrapolated to total U.S. refinery capacity to estimate total emissions from waste gas streams for 1990. To estimate emissions for 1991 to 1996, the 1990 emission estimates were scaled using updated data on U.S. refinery capacity (EIA, 1991-96, 1997).

Transportation. EPA uses proxies to estimate emissions from crude tanker operations. For domestic crude, the estimate is for Alaskan crude offloaded in the continental U.S.; for imports, the estimate is for the total imported less imports from Canada. An emission factor from Tilkicioglu and Winters (1989) based on the methane content of hydrocarbon vapors emitted from crude oil is multiplied by the crude oil tanker handling estimates. Data on crude oil stocks, crude oil production, utilization, and imports are obtained from EIA (1991-96, 1997).

Venting and Flaring. Of the five activity categories, venting and flaring can occur at all stages of crude oil production and handling. However, for EPA methane emission estimates, venting and flaring is treated as a separate activity. Data from EIA (1991-96, 1997) indicate that venting and flaring activities have changed over time for a variety of reasons. Given the considerable uncertainty in the emission estimate for this category, and the inability to discern a trend in actual emissions, the 1990 emission estimate is used for the years 1991-1997.

EPA is revising the method for estimating methane emissions from oil production so that it will be more similar to the approach for natural gas systems. The revised approach, based on EPA and API work (1997), uses a much more disaggregated description of the crude oil production sector and activity and emission factors for specific equipment to generate the emission estimates. EPA expects to employ the new method for EPA's 1998 U.S. inventory estimates which will be published in 2000.

1.3 Emission Estimates

This section presents the current emission estimates for natural gas and oil systems and a forecast of emissions from natural gas systems.

Exhibit 3-3: Oil Industry Activities for Current Emission Estimates

Activity	Description
Production Field	Fugitive emissions from oil wells and related production field treatment and separation equipment
Crude Oil Storage	Crude oil storage tanks emit methane when oil is cycled through the tanks and hydrocarbons escape solution
Refining Waste Gas Streams	A variety of sources within refinery operations emit gas
Transportation (Tanker Operations)	Emissions occur as tankers are loaded and unloaded
Venting and Flaring	Gas that cannot be captured during production is vented or flared

1.3.1 Current Emissions and Trends

U.S. natural gas systems emitted 33.5 million metric tons of carbon equivalent (MMTCE) or 5.8 Teragrams (Tg) of methane in 1997 or about 19 percent of total U.S. anthropogenic methane emissions, as Exhibit 3-4 shows. These methane emissions from gas systems account for about one percent of the natural gas consumed in the U.S. in 1997. Emissions have increased slightly from 1990 reflecting an increase in the number of producing gas wells and distribution pipeline mileage. The increase in emissions was slowed by the emission reductions reported by Partners in EPA's Natural Gas STAR Program, one of the U.S. Climate Change Action Plan (CCAP) programs. The Natural Gas STAR Program was initiated in 1994 and works with natural gas and oil companies to identify and promote Best Management Practices (BMPs) and Partner Reported Opportunities (PROs) that reduce methane emissions cost-effectively.

From 1990 to 1997, methane emissions from oil system activities remained relatively constant at approximately 1.6 MMTCE (0.3 Tg). Currently, no CCAP program is devoted to reducing methane emissions from oil systems; however, the Natural Gas STAR Program includes BMPs that reduce methane emissions from oil systems. Exhibit 3-5 presents the emission estimates from oil systems. EPA is revising the estimation method for oil systems and expects estimates to increase.

1.3.2 Future Emissions and Trends

Natural Gas. Future emissions from natural gas systems are estimated by forecasting both emission factors and activity factors from the 1992 base year factors developed by EPA and GRI (1996). As noted above, EPA assumes that emission factors decline by a total of five percent between 1995 and 2020 as the existing stock of equipment is gradually replaced with newer and more efficient equipment.

Exhibit 3-4: Methane Emissions from Natural Gas Systems (MMTCE)

Source	1990	1991	1992	1993	1994	1995	1996	1997
Production	8.0	8.2	8.5	8.7	8.8	9.1	9.5	9.5
Processing	4.0	4.0	4.0	4.0	4.2	4.1	4.1	4.1
Transmission/Storage	12.6	12.7	12.9	12.6	12.5	12.5	12.4	12.7
Distribution	8.3	8.4	8.6	8.8	8.7	8.7	9.1	8.9
Sub-Total	**32.9**	**33.3**	**33.9**	**34.1**	**34.2**	**34.3**	**35.0**	**35.1**
CCAP Reductions[a]	–	–	–	–	(0.7)	(1.2)	(1.3)	(1.6)
Total	**32.9**	**33.3**	**33.9**	**34.1**	**33.5**	**33.2**	**33.7**	**33.5**

[a] CCAP reductions are from the Natural Gas STAR Program.
Totals may not sum due to independent rounding.
Source: EPA, 1999.

Exhibit 3-5: Methane Emissions from Oil Systems (MMTCE)

Source	1990	1991	1992	1993	1994	1995	1996	1997
Production	0.14	0.14	0.14	0.14	0.14	0.13	0.13	0.13
Crude Oil Storage	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Transportation	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.06
Refining	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05
Venting & Flaring	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32
Total	**1.56**	**1.56**	**1.56**	**1.56**	**1.56**	**1.55**	**1.55**	**1.55**

Totals may not sum due to independent rounding.
Source: EPA, 1999.

The principal drivers of future activity factors are the levels of gas consumption and domestic production, including the necessary expansions in industry infrastructure to meet these market levels. Using the consumption and production forecasts from the EIA's *Annual Energy Outlook* (EIA, 1998), EPA estimates the changes in infrastructure necessary to meet these consumption and production levels. Exhibit 3-6 presents forecasts of baseline methane emissions from natural gas systems through 2020. Unless actions are taken to reduce emissions, natural gas systems will emit 13 percent more methane in 2020 than in 1992, mostly due to growth in natural gas consumption and the associated growth in infrastructure. The forecast methodology is described below.

- **Production Sector.** Methane emissions from natural gas production depend on the number of wells needed for the forecast level of production and the location of the wells, since operating characteristics and equipment profiles vary by region. EPA uses the Gas Systems Analysis Model (GSAM) to estimate the number of wells. GSAM represents over 16,000 reservoirs, the entire gas transmission network and gas markets, and it identifies the number of wells needed to generate the forecast output and the location of these wells. From these forecasts, EPA estimates the emissions associated with ancillary well equipment, such as dehydrators, separators, heaters, and meters.

- **Processing Sector.** Processing and related equipment associated with emissions are scaled to domestic production.

- **Transmission and Storage Sector.** Transmission and storage emissions are related to forecasts of domestic consumption (sum of net production and imports). For compressors and their operations (hours in service per year), EPA generates emission estimates based on the pipeline throughput necessary to meet projected consumption. An increase in customers leads to an increase in pipeline mileage. Emission increases from storage operations and related equipment are associated with growth in consumption.

- **Distribution Sector.** The major sources of emissions from the distribution sector are gate stations, metering and pressure regulating equipment, and cast iron and unprotected steel distribution pipe. Emissions depend on the number of customers, consumption, and the rate of cast iron and unprotected steel pipe replacement. The forecast method uses consumption and pipe replacement statistics to estimate future distribution activity factors (EPA/GRI, 1996).

Oil. EPA's current forecast of emissions from oil systems—1.6 MMTCE in 2010, 1.7 MMTCE in 2020—is being revised. The new estimate will reflect that methane emissions from oil systems are directly proportional to the overall size of the petroleum industry. DOE expects U.S. demand for petroleum products to grow by 1.2 percent annually between 1996 and 2020, from 18.4 million barrels per day in 1996 to 24.3 million barrels per day in 2020 (EIA, 1998).

1.4 Emission Estimate Uncertainties

Natural Gas. Uncertainties in the emission estimates stem from the size, complexity, and heterogeneity of the infrastructure of the U.S. natural gas industry. In this analysis, the estimate of methane emissions from natural gas systems is accurate to within plus or minus 25 percent. The estimate of overall accuracy is based on separate assessments of the uncertainties surrounding each activity factor and emission factor used

Exhibit 3-6: Projected Baseline Methane Emissions from Natural Gas Systems (MMTCE)

Source	2000	2005	2010	2015	2020
Production	9.2	9.8	10.6	11.1	10.8
Processing	4.2	4.4	4.6	4.6	4.8
Transmission	13.5	13.7	14.0	14.3	14.6
Distribution	8.8	8.8	8.8	8.7	8.7
Total	**35.6**	**36.7**	**37.9**	**38.7**	**38.8**

Totals may not sum due to independent rounding.

in developing the emission estimate. The total uncertainty range is the sum of the individual uncertainties for each emission source.

Oil. Compared to the natural gas industry, greater uncertainties are associated with all aspects of the methane emission estimates for the oil industry. EPA believes that the current estimation method significantly understates emissions and that methane emissions may be four to five times greater than the estimated 1.6 MMTCE (0.3 Tg) presented here. As noted above, the method for estimating methane emissions from petroleum systems is being updated.

2.0 Emission Reductions

This section describes how EPA estimates the costs and benefits of achieving emission reductions at different potential values for methane. The value of abated methane is the market price of the methane as natural gas, in \$/MMBtu, and also may include a carbon equivalent value for emission reductions, if available. The analysis only assesses reductions from natural gas systems and does not include oil systems.

2.1 Technologies for Reducing Methane Emissions

A number of technologies and practices have been identified that can reduce methane emissions from natural gas systems. EPA and the natural gas industry, through the Natural Gas STAR Program, have identified several Best Management Practices (BMPs) that are cost-effective in reducing methane emissions. The Natural Gas STAR Program has sponsored a series of Lessons Learned Studies of these BMPs and several other practices. These studies provide detailed information on the costs of achieving methane emission reductions (EPA, 1997a-h). In addition, companies that are Natural Gas STAR Partners have identified other practices that also reduce methane emissions. The cost analysis described herein is based on the BMPs and Partner-Reported Opportunities (PROs) listed in Exhibit 3-7. More details of these BMPs and PROs are found in Appendix III, Exhibits III-3 and III-4.

2.2 Cost Analysis of Emission Reductions

The objective of the cost analysis is to develop a marginal abatement curve (MAC) from the available options for reducing methane emissions. The MAC is presented as a schedule of emission reductions that could be obtained at increasing values for methane. The analysis considers the value of methane as the sum of its market value as natural gas and a market value for emission reductions represented in dollars per metric ton of carbon equivalent (\$/TCE).[1] The MAC is based on a discounted cash flow analysis of the reduction options listed in Exhibit 3-7. The steps in this analysis are described below.

Step 1: Characterize the Reduction Options. Each

Exhibit 3-7: Methane Emission Reduction Options

Natural Gas STAR Best Management Practices

- ✓ Replace or repair high-bleed pneumatic devices with low-bleed devices
- ✓ Practice directed inspection and maintenance at compressor stations
- ✓ Install flash tanks on glycol dehydrators
- ✓ Practice directed inspection and maintenance of gate stations and surface facilities
- ✓ Replace cast iron distribution mains with steel or plastic pipe
- ✓ Replace cast iron distribution services pipe with steel or plastic pipe

Natural Gas STAR Partner-Reported Opportunities

- ✓ Practice directed inspection and maintenance at production sites, processing sites, transmission pipelines, storage wells, and liquid natural gas stations
- ✓ Practice enhanced directed inspection and maintenance, i.e., more frequent survey and repair at production sites, surface facilities, storage wells, offshore platforms, and compressor stations
- ✓ Install electric starters on compressors
- ✓ Install plunger lifts at production wells
- ✓ Use capture vessels for blowdowns at processing plants and other facilities
- ✓ Install instrument air systems
- ✓ Replace/repair chemical injection pumps
- ✓ Use portable evacuation compressors for pipeline repairs
- ✓ Install catalytic converters on compressor engines
- ✓ Conduct electronic metering at gate stations
- ✓ Install fuel gas retrofit systems on compressors to capture otherwise vented fuel when compressors are taken off-line
- ✓ Install static seal systems on reciprocating compressor rods
- ✓ Install dry seal systems on centrifugal compressors
- ✓ Reduce circulation rates on glycol dehydrators

option for reducing methane emissions is defined in the following terms: the emission source to which it applies; capital cost; the number of years that the capital equipment lasts (typically 5 to 15 years depending on the technology); annual operating and maintenance costs; and its efficiency, i.e., achievable emission reduction (up to 100 percent).

The options are matched to emission source definitions in the emission inventory analysis (EPA/GRI, 1996). In addition, in some cases the technologies and practices must be considered in proper order. For example, when identifying potential emission reductions from glycol dehydrators (which remove water during natural gas processing), the option of reducing the glycol recirculation rate must be considered before the higher-cost option of installing flash tanks. EPA assumes that lower-cost options are implemented first, and so the potential emission reductions from flash tanks depend on the remaining volume of emissions after glycol recirculation rates have been reduced. In this way, relationships are defined so that incremental emission reductions are analyzed for each option. In Appendix III, Exhibits III-5 and III-6 list the data used to define the reduction options.

Options can be applied in different segments of the industry and in different settings within each segment. For example, replacing high-bleed pneumatic devices with low-bleed pneumatic devices is applicable in the production, transmission, and distribution sectors. Within each sector, pneumatic devices can be applied at sites with high or low volume throughput.

Step 2: Calculate Break-Even Gas Prices. A discounted cash flow analysis is performed for each emission reduction option to estimate the price of natural gas needed to offset the cost of the option for reducing emissions. The analysis is conducted from the perspective of a private decision-maker in the natural gas industry. Exhibit 3-8 shows the financial assumptions used.

Step 3: Estimate Cost-Effective Emission Reductions for Each Option. The analysis compares the needed break-even price for each methane reduction option against the total value of the abated methane which is the sum of the market value of gas and any emission reduction values. If the value for the abated methane (revenue) is equal to or greater than an option's cost, that option is considered cost-effective. Overall for the gas industry, about one-third of the baseline emissions in 2010 can be cost-effectively reduced at the market value of gas alone, that is, with no additional carbon equivalent values or $0/TCE. More reductions could be achieved with the addition of higher carbon equivalent values. The estimates of achievable reductions are option-specific, which means they are also sector-specific.

Step 4: Generate the Marginal Abatement Curve. The MAC is derived by rank ordering the cost-effective individual opportunities at each combination of gas price and carbon-equivalent emission reduction values. The MAC can also be called a cost or supply curve since it shows the cost per emission reduction amount.

Exhibit 3-8: Financial Assumptions for Emission Reduction Analysis

Parameter	Description
Value of Gas Saved (1996 US$)	Wellhead: $2.17 / MMBtu Pipeline: $2.27 / MMBtu Distribution citygate: $3.27 / MMBtu
Discount Rate	20 percent real
Project Lifetime	5 years
Tax Rate	40 percent
Capital Costs	Vary with equipment
Depreciation Period	Maximum 5 years for large investments; 1 year for small investments
Operating & Maintenance Costs	Expressed as annual costs

2.3 Achievable Emission Reductions and Marginal Abatement Curve

Exhibit 3-9 presents the cumulative emission reductions for selected values of carbon equivalent in 2000, 2010, and 2020. Exhibit 3-10 illustrates how the technologies and practices for reducing methane emissions are applied to the natural gas industry. Given the generic nature of some of the options, e.g., directed inspection and maintenance (DI&M), the options can have different cost and savings when applied to different sectors of the industry, and within sectors to different kinds of equipment.

Exhibit 3-9: Emission Reductions at Selected Values of Carbon Equivalent in 2000, 2010, and 2020 (MMTCE)

	2000	2010	2020
Baseline Emissions	35.6	37.9	38.8
Cumulative Reductions			
at $0/TCE	10.1	10.8	11.0
at $10/TCE	11.6	12.4	12.7
at $20/TCE	11.7	12.5	12.8
at $30/TCE	12.5	13.3	13.6
at $40/TCE	12.5	13.3	13.6
at $50/TCE	14.4	15.3	15.6
at $75/TCE	15.3	16.3	16.7
at $100/TCE	17.4	18.4	18.9
at $125/TCE	18.0	19.2	19.6
at $150/TCE	18.1	19.2	19.7
at $175/TCE	18.1	19.2	19.7
at $200/TCE	18.1	19.3	19.7
Remaining Emissions	17.5	18.6	19.1

The cost effectiveness of an emission reduction option is higher when applied to operations that have greater opportunities to reduce emissions, i.e., components with high throughputs and components that operate continuously versus intermittently. For example, among meter and regulating stations in the distribution sector, DI&M is more cost-effective at larger stations with greater flows of gas than at smaller stations.

The value of natural gas to the system operator also affects the cost-effectiveness of an emission reduction option. Broadly speaking, natural gas is least valuable at the wellhead, i.e., the production sector, and most valuable in the citygate market, i.e., the distribution sector. The cost analysis recognizes this market characteristic by using three sector-specific natural gas prices: $2.17/MMBtu for wellhead, for $2.27/MMBtu for pipeline, and $3.27/MMBtu for citygate.

While a limited number of options are considered, applying these options to various segments of the industry (with corresponding different gas values) and to different equipment types results in the evaluation of 118 opportunities to reduce emissions. Appendix III, Exhibit III-7 provides a full list of these opportunities.

Exhibit 3-11 is derived from Exhibit 3-10 and presents the MAC showing the additional amounts of abated methane per increases in the price of natural gas—the left vertical axis—and additional carbon equivalent values ($/TCE)—the right vertical axis. The horizontal axis is the amount of abated methane.

The energy market price, $2.43/MMBtu in 1996, is aligned to $0/TCE. At $0/TCE, no additional price signals exist from carbon equivalent values to motivate emission reductions; all emission reductions are due to a response to the price of natural gas. As a value is placed on avoided emissions in terms of $/TCE, these values are added to the energy market prices and allow for additional emissions to clear the market. The "below-the-line" amounts, with respect to $/TCE, illustrate this dual price-signal market.

While the detailed analysis uses three different natural gas prices to reflect the increasing value of natural gas as it moves through the system, these three prices were averaged into a single price of $2.43/MMBtu to simplify Exhibit 3-10. Average natural gas prices were also used to calculate carbon equivalent values and cumulative emission reductions in Exhibit 3-10. Sector-specific natural gas prices were used to calculate incremental emission reductions.

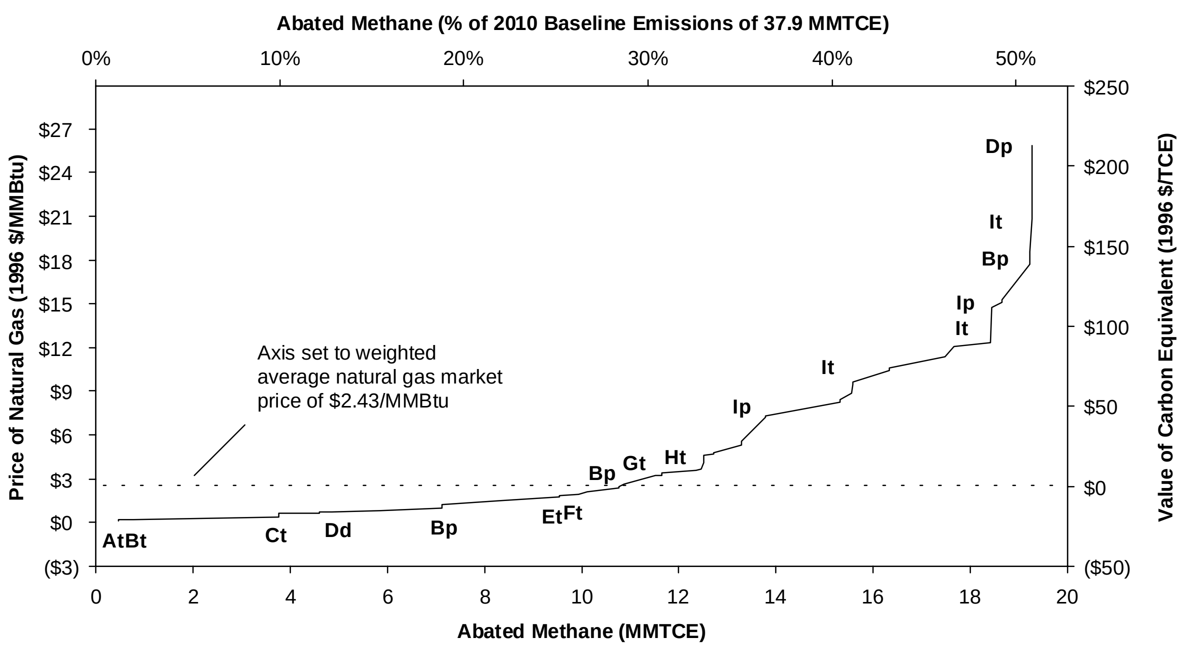
The MAC shows that approximately 30 percent of baseline emissions can be cost-effectively reduced at $2.43/MMBtu, the average market natural gas price. At approximately $100/TCE, the MAC becomes inelastic, that is, non-responsive to any increases in the value for abated methane. Further reductions in methane emissions beyond about 50 percent of the baseline are limited given the current set of options evaluated (see below).

Exhibit 3-10: Schedule of Selected Methane Emission Reduction Options in 2010

Option	Based on Sector-Specific Natural Gas Prices		Based on Industry Average Natural Gas Price		
	Break-Even Gas Price	Incremental Reductions (MMTCE)	Value of Carbon Equivalent ($/TCE)	Cumulative Reductions (MMTCE)	Label on MAC
Install fuel gas retrofit systems on compressors to capture otherwise vented fuel when compressors are taken off-line	$0.12	0.42	($21.06)	0.47	At
Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to high-bleed, continuous-bleed pneumatic devices)	$0.20	0.59	($20.28)	0.78	Bt
Reduce glycol circulation rates in dehydrators (not applicable to Kimray pumps, this option applies to dehydrators with gas assisted pumps but without flash tanks)	$0.45	0.28	($18.03)	3.76	Ct
Practice directed inspection and maintenance at gate stations and surface facilities	$0.75	0.14	($15.26)	4.87	Dd
Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to high bleed, intermittent bleed devices)	$1.00	0.90	($13.01)	7.13	Bp
Install reciprocating compressor rod packing (Static-Pac)	$1.81	0.06	($5.61)	9.54	Et
Install dry seals on centrifugal compressors	$1.91	0.12	($4.73)	9.93	Ft
Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to medium-bleed, intermittent-bleed devices)	$2.50	0.68	$0.63	10.78	Bp
Install flash tank separators	$3.42	0.02	$9.01	11.66	Gt
Conduct electronic monitoring at large surface facilities only	$4.84	0.06	$21.87	12.72	Ht
Replace high-bleed pneumatic devices with compressed air systems[a] (applies to high-bleed, intermittent-bleed devices)	$7.21	0.32	$43.46	13.79	Ip
Replace high-bleed pneumatic devices with compressed air systems[a] (applies to high-bleed turbine devices)	$9.68	0.10	$65.97	15.57	It
Replace high-bleed pneumatic devices with compressed air systems[a] (applies to low-bleed, continuous-bleed devices)	$12.34	0.78	$90.15	18.42	It
Replace high-bleed pneumatic devices with compressed air systems[a] (applies to medium-bleed, intermittent-bleed devices)	$14.77	0.22	$112.20	18.45	Ip
Replace higher-bleed pneumatic devices with lower-bleed pneumatic devices (applies to low-bleed, intermittent-bleed devices)	$18.00	0.01	$141.56	19.22	Bp
Replace high-bleed pneumatic devices with compressed air systems[a] (applies to medium-bleed turbine devices)	$20.81	0.04	$167.11	19.26	It
Practice directed inspection and maintenance at production sites	$25.88	0.02	$213.24	19.29	Dp

[a] This option is coordinated with the option of replacing high-bleed pneumatic devices with low-bleed pneumatic devices.

Exhibit 3-11: Marginal Abatement Curve for Methane Emissions from Natural Gas Systems in 2010



LEGEND

Emission Reduction Options

A	=	fuel gas retrofit
B	=	replace higher-bleed pneumatic devices with lower-bleed devices
C	=	reduce glycol circulation rates in dehydrators
D	=	directed inspection and maintenance (DI&M)
E	=	reciprocating compressor rod packing (Static-Pac)
F	=	dry seals on reciprocating compressors
G	=	flash tank separators
H	=	electronic monitoring at large surface facilities
I	=	replace high-bleed pneumatic devices with compressed air

Natural Gas Industry Sectors

p	=	applied to the production sector
t	=	applied to the transmission sector
d	=	applied to the distribution sector

Note: More than one point can have the same code because the same emission reduction option can be applied to different components of a sector.

2.4 Reduction Estimate Uncertainties and Limitations

The two major areas of uncertainty related to the MAC are: (1) an exclusive focus on currently available technologies; and (2) a lack of data on some of the technologies currently used by industry. By focusing on options that have been reviewed by the Natural Gas STAR Program, the study has not included the possibility that other technologies will be developed in the future that can further reduce methane emissions more efficiently. In addition, data on the PROs is incomplete in many cases. EPA's Natural Gas STAR Program has an ongoing effort to develop more detailed analyses of these opportunities.

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4.0 Explanatory Notes

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[1] Equation to calculate the equivalent gas price for a given value of carbon equivalent:

$$\frac{\$}{TCE} \; x \; \frac{10^6 \, TCE}{MMTCE} \; x \; \frac{5.73 \, MMTCE}{Tg \, CH_4} x \; \frac{Tg}{10^{12} \, g} \; x \; \frac{19.2 \, g \, CH_4}{ft^3 \, CH_4} \; x \; \frac{ft^3}{1{,}000 \, Btu} \; x \; \frac{10^6 \, Btu}{MMBtu} = \frac{\$}{MMBtu}$$

Where: 5.73 MMTCE/Tg CH_4 = 21 CO_2/CH_4 x (12 C / 44 CO_2)
Density of CH_4 = 19.2 g/ft^3
Btu content of CH_4 = 1,000 Btu/ft^3

Appendix III: Supporting Material for the Analysis of Natural Gas Systems

This appendix presents the detailed data that EPA used to develop methane emission forecasts and to estimate emission reduction costs. Exhibits III-1 and III-2 describe the emission factors, activity factors, and the activity factor drivers used to estimate annual changes in emissions and for forecasting future emissions. Exhibits III-3 and III-4 describe the specific options available for reducing emissions from gas systems. A summary of the costs of the specific options is summarized in Exhibits III-5 and III-6. Finally, Exhibit III-7 presents the data used to generate the marginal abatement curve for natural gas systems. The exhibits are summarized below.

- **Exhibit III-1: Activity Factors and Emission Factors.** This exhibit summarizes the activity and emission factors and the resulting emissions by source for 1992, which is the year covered by the EPA/GRI 1996 report, and the year on which emission estimates for all other years are based (EPA/GRI, 1996). For this analysis, the natural gas industry is divided into sectors: production, gas processing, transmission, and distribution. Within each sector, emissions are categorized as fugitives (leaks) and vented and combusted. Each line represents an emission source in the industry and sector. The emissions, expressed in tons of methane, are the product of the activity factor and the annualized emission factor, which is expressed in cubic feet of methane (standard cubic feet per day (scfd); thousand standard cubic feet per year (Mscfy)).
- **Exhibit III-2: Driver Variables.** The activity drivers and sources for the driver estimates are listed in this exhibit. Activity drivers are used to estimate emissions based on changes in characteristics of the natural gas industry. These characteristics include gas production, gas consumption, customers, miles of pipeline, number of wells, distribution infrastructure and other variables. The sources of data are primarily from publications produced by the Energy Information Administration, the American Petroleum Institute, and the Independent Petroleum Association of America.
- **Exhibit III-3: Best Management Practices.** This exhibit presents the Best Management Practices (BMPs) that EPA used to develop the cost curves for reducing methane emissions from the natural gas industry. The BMPs were identified by the Natural Gas STAR Program, a voluntary industry-EPA partnership created to identify cost-effective technologies and practices to reduce methane emissions.
- **Exhibit III-4: Partner-Reported Opportunities.** This exhibit presents the Partner-Reported Opportunities (PROs) that EPA used to develop the cost curves for reducing methane emissions from the natural gas industry. The PROs were identified by the Natural Gas STAR industry Partners as part of their efforts to reduce methane emissions cost-effectively.
- **Exhibit III-5: Cost Analysis Data and Assumptions for Best Management Practices.** This exhibit describes the BMPs in terms of their applicability to the natural gas industry, potential emission reductions once applied, capital and operation and maintenance costs, and break-even gas price.
- **Exhibit III-6: Cost Analysis Data and Assumptions for Partner-Reported Opportunities.** This exhibit describes the PROs in terms of their applicability to the natural gas industry, potential

emission reductions once applied, capital and operation and maintenance costs, and break-even gas price.

- **Exhibit III-7: Schedule of Emission Reduction Options for 2010.** The 118 emission reduction options used to generate the marginal abatement curve (MAC) for reducing methane emissions from U.S. natural gas systems are provided in this exhibit. All options are described in terms of their break-even gas price, base gas price type, value of carbon equivalent required in addition to the base gas price to make the option cost-effective, and incremental emission reduction.

Exhibit III-1: Activity Factors and Emission Factors[a]					
Segment	**Activity Factor**	**Units**	**Emission Factor**	**Units**	**Emissions (Tons of Methane)**
PRODUCTION					**1,476,877**
Normal Fugitives					
Gas Wells (Eastern on shore)					
Appalachia (all non-associated)	123,585 [b]	wells	7.11	scfd/well	6,157.85
N. Central					
Associated Gas Wells	3,507 [b]	wells	-	scfd/well	-
Non-Associated Gas Wells	4,977 [b]	wells	7.11	scfd/well	247.99
Field Sep. Equip. (Eastern on shore)					
Heaters	260	heaters	14.21	scfd/heater	25.89
Separators					
Appalachia	79,377	separators	0.90	scfd/sep	500.64
N. Central	12,293	separators	0.90	scfd/sep	77.54
Gathering Compressors					
Small Reciprocating Compressor					
Appalachia	4,943	compressors	12.10	scfd/comp	419.18
N. Central					
Associated Gas	270 [b]	compressors	12.10	scfd/comp	22.93
Non-Associated Gas	324 [b]	compressors	12.10	scfd/comp	27.48
Meters/Piping	11,693	meters	9.01	scfd/meter	738.30
Dehydrators	674	dehydrators	21.75	scfd/dehy	102.73
Gas Wells (Rest of U.S. on shore)	142,771 [b]	wells	36.40	scfd/well	36,419.53
Associated Gas Wells Rest of U.S.	256,226 [b]	wells	-	scfd/well	-
Gulf of Mexico Off-Shore Platforms	1,350 [b]	platforms	2,914.00	scfd/plat	27,568.77
Rest of U.S. (Off-Shore platforms)	22 [b]	platforms	1,178.00	scfd/plat	181.62
Field Separation Equipment - Rest of U.S. On Shore					
Heaters	50,740	heaters	57.70	scfd/heater	20,517.14
Separators	74,670	separators	122.00	scfd/sep	63,841.09
Gathering Compressors					
Small Reciprocating Compressor	16,915 [b]	compressors	267.80	scfd/comp	31,745.18
Large Reciprocating Compressor	96	compressors	15,205.00	scfd/comp	10,229.44
Large Reciprocating Compressor	12	stations	8,247.00	scfd/station	693.54
Meters/Piping	177,438	meters	52.90	scfd/meter	65,780.56
Dehydrators	24,289	dehydrators	91.10	scfd/dehy	15,506.55
Pipeline Leaks	340,200	miles	53.20	scfd/mile	126,835.09
Vented and Combusted					
Drilling and Well Completion					
Completion Flaring	400 [b]	compl/yr	733.00	scf/comp	5.63
Normal Operations					
Pneumatic Device Vents	249,111 [b]	controllers	345.00	scfd/device	602,291.32
Chemical Injection Pumps	16,971	active pumps	248.05	scfd/pump	29,501.85
Kimray Pumps	7,380,194	MMscf/yr	992.00	scf/MMscf	140,566.12
Dehydrator Vents	8,200,215	MMscf/yr	275.57	scf/MMscf	43,386.88
Compressor Exhaust Vented					
Gas Engines	27,460 [b]	MMHPhr	0.24	scf/HPhr	126,535.33
Routine Maintenance					
Well Workovers					
Gas Wells	9,392	w.o./yr	2,454.00	scfy/w.o.	442.52
Well Clean Ups (LP Gas Wells)	114,139	LP gas wells	49,570.00	scfy/LP well	108,630.91
Blowdowns					
Vessel BD	242,302	vessels	78.00	scfy/vessel	362.87
Pipeline BD	340,200	miles (gath)	309.00	scfy/mile	2,018.34
Compressor BD	17,112	compressors	3,774.00	scfy/comp	1,239.95
Compressor Starts	17,112	compressors	8,443.00	scfy/comp	2,773.96
Upsets					
Pressure Relief Valves	529,440 [b]	PRV	34.00	scfy/PRV	345.62

Exhibit III-1: Activity Factors and Emission Factors[a] (continued)					
Segment	Activity Factor	Units	Emission Factor	Units	Emissions (Tons of Methane)
PRODUCTION (continued)					
Vented and Combusted (continued)					
ESD	1,372	platforms	256,888.00	scfy/plat	6,767.05
Mishaps	340,200	miles	669.00	scfy/mile	4,369.79
GAS PROCESSING PLANTS					**697,555**
Normal Fugitives					
Plants	726 [b]	plants	7,906.00	scfd/plant	40,224.08
Recip. Compressors	4,092 [b]	compressors	11,196.00	scfd/comp	321,066.39
Centrifugal Compressors	726 [b]	compressors	21,230.00	scfd/comp	108,014.07
Vented and Combusted					
Normal Operations					
Compressor Exhaust					
Gas Engines	27,460 [b]	MMHPhr	0.24	scf/HPhr	126,535.45
Gas Turbines	32,910 [b]	MMHPhr	0.01	scf/HPhr	3,601.67
AGR Vents	371	AGR units	6,083.00	scfd/AGR	15,814.96
Kimray Pumps	957,930	MMscf/yr	177.75	scf/MMscf	3,269.22
Dehydrator Vents	8,630,003 [b]	MMscf/yr	121.55	scf/MMscf	20,140.36
Pneumatic Devices	726	gas plants	164,721.00	scfy/plant	2,296.07
Routine Maintenance					
Blow downs/Venting	726	gas plants	4,060.00	Mscfy/plant	56,592.96
Fugitives					
Pipeline Leaks	284,500 [b]	miles	1.54	scfd/mile	3,072.41
Compressor Stations (Trans.)					
Station	1,700	stations	8,778.00	scfd/station	104,605.04
Recip Compressor	6,799	compressors	15,205.00	scfd/comp	724,478.87
Centrifugal Compressor	681	compressors	30,305.00	scfd/comp	144,629.14
Compressor Stations (Storage)					
Station	386 [b]	stations	21,507.00	scfd/station	58,178.33
Recip Compressor	1,135	compressors	21,116.00	scfd/comp	167,958.35
Centrifugal Compressor	111	compressors	30,573.00	scfd/comp	23,782.37
Wells (Storage)	17,999	wells	114.50	scfd/well	14,442.69
M&R (Trans. Co. Interconnect)	2,532	stations	3,984.00	scfd/station	70,694.51
M&R (Farm Taps + Direct Sales)	72,630	stations	31.20	scfd/station	15,880.59
Vented and Combusted					
Normal Operation					
Dehydrator Vents (Transmission)	1,086,001	MMscf/yr	93.72	scf/MMscf	1,954.18
Dehydrator Vents (Storage)	2,000,001 [b]	MMscf/yr	117.18	scf/MMscf	4,499.71
Compressor Exhaust					
Engines (Transmission)	40,380 [b]	MMHPhr	0.24	scf/HPhr	186,071.04
Turbines (Transmission)	9,635 [b]	MMHPhr	0.01	scf/HPhr	1,054.45
Engines (Storage)	4,922 [b]	MMHPhr	0.24	scf/HPhr	22,680.58
Turbines (Storage)	1,729 [b]	MMHPhr	0.01	scf/HPhr	189.22
Generators (Engines)	1,976 [b]	MMHPhr	0.24	scf/HPhr	9,105.42
Generators (Turbines)	23 [b]	MMHPhr	0.01	scf/HPhr	2.55
Pneumatic Devices Trans + Storage					
Pneumatic Devices Trans	68,103	devices	162,197.00	scfy/device	212,084.78
Pneumatic Devices Storage	15,460	devices	162,197.00	scfy/device	48,145.26
Routine Maintenance/Upsets					
Pipeline Venting	284,500	miles	31.65	Mscfy/mile	172,884.96
Station venting Trans + Storage					
Station Venting Transmission	1,700	cmp stations	4,359.00	Mscfy/station	142,315.12
Station Venting Storage	386	cmp stations	4,359.00	Mscfy/station	32,305.42

Exhibit III-1: Activity Factors and Emission Factors[a] (continued)

Segment	Activity Factor	Units	Emission Factor	Units	Emissions (Tons of Methane)
TRANSMISSION					**2,228,280**
LNG Storage					
LNG Stations	64 [b]	stations	21,507.00	scfd/station	9,646.15
LNG Reciprocating Compressors	246 [b]	compressors	21,116.00	scfd/comp	36,403.31
LNG Centrifugal Compressors	58 [b]	compressors	30,573.00	scfd/comp	12,426.82
LNG Compressor Exhaust					
LNG Engines	741 [b]	MMHPhr	0.24	scf/HPhr	3,414.53
LNG Turbines	162 [b]	MMHPhr	0.01	scf/HPhr	17.73
LNG Station Venting	64	cmp stations	4,359.00	Mscfy/station	5,356.34
DISTRIBUTION					**1,495,565**
Normal Fugitives					
Pipeline Leaks					
Mains - Cast Iron	55,288 [b]	miles	238.70	Mscf/mile-yr	253,387.12
Mains - Unprotected Steel	82,109 [b]	miles	110.19	Mscf/mile-yr	173,706.87
Mains - Protected Steel	444,768	miles	3.12	Mscf/mile-yr	26,623.73
Mains – Plastic	254,595	miles	19.30	Mscf/mile-yr	94,324.89
Total Pipeline Miles	836,760 [b]	.			
Services - Unprotected Steel	5,446,393 [b]	services	1.70	Mscf/service	177,815.33
Services Protected Steel	20,352,983 [b]	services	0.18	Mscf/service	69,000.53
Services – Plastic	17,681,238	services	0.01	Mscf/service	3,161.82
Services – Copper	233,246 [b]	services	0.25	Mscf/service	1,138.36
Total Services	43,713,860 [b]				
Meter/Regulator (City Gates)					
M&R >300 psi	3,580	stations	179.80	scfh/station	108,277.61
M&R 100-300 psi	13,799	stations	95.60	scfh/station	221,882.88
M&R <100 psi	7,375	stations	4.31	scfh/station	5,346.34
Reg >300 psi	4,134	stations	161.90	scfh/station	112,573.59
R-Vault >300 psi	2,428	stations	1.30	scfh/station	530.82
Reg 100-300 psi	12,700	stations	40.50	scfh/station	86,512.45
R-Vault 100-300 psi	5,706	stations	0.18	scfh/station	172.75
Reg 40-100 psi	37,593	stations	1.04	scfh/station	6,575.79
R-Vault 40-100 psi	33,337	stations	0.09	scfh/station	485.01
Reg <40 psi	15,913	stations	0.13	scfh/station	355.96
Customer Meters					
Residential	40,049,306 [b]	outdr meters	138.50	scfy/meter	106,499.11
Commercial/Industry	4,607,983 [b]	meters	47.90	scfy/meter	4,237.87
Vented					
Routine Maintenance					
Pressure Relief Valve Releases	836,760	mile main	0.05	Mscf/mile	803.29
Pipeline Blowdown	1,297,569 [b]	Miles	0.10	Mscfy/mile	2,541.16
Upsets					
Mishaps (Dig-ins)	1,297,569	miles	1.59	mscfy/mile	39,612.18
TOTAL					**5,898,278**

[a] Data are for base year 1992, the year covered by the EPA/GRI 1996 report, and the year from which emission estimates for all other years are based.
[b] Main driver for the emission inventory.
Source: EPA/GRI, 1996.

Exhibit III-2: Driver Variables

Variable	Units	Source
Dry Gas Production: National Total	Tcf / yr	EIA (www.eia.doe.gov), *Natural Gas Monthly*, Table of Supply and Disposition of Dry Natural Gas in the United States, 1992-1997
Dry Gas Production: National Total minus Alaska	Tcf / yr	Calculated, based on an estimate of gas production in Alaska
Gas Production: Alaska	Tcf / yr	Estimate, based on EIA data (www.eia.doe.gov), *Natural Gas Monthly*, Table of Marketed Production of Natural Gas By State
Gas Consumption: National Total	Tcf / yr	EIA (www.eia.doe.gov), *Natural Gas Monthly*, Table of Natural Gas Consumption in the United States, 1992-1997
Gas Consumption: Residential	Tcf / yr	EIA (www.eia.doe.gov), *Natural Gas Monthly*, Table of Natural Gas Consumption in the United States, 1992-199
Gas Consumption: Commercial	Tcf / yr	EIA (www.eia.doe.gov), *Natural Gas Monthly*, Table of Natural Gas Consumption in the United States, 1992-1997
Gas Consumption: Industrial	Tcf / yr	EIA (www.eia.doe.gov), *Natural Gas Monthly*, Table of Natural Gas Consumption in the United States, 1992-1997
Gas Consumption: Electrical Generators	Tcf / yr	Estimate, based on EIA data (www.eia.doe.gov), *Natural Gas Monthly*, Table of Natural Gas Deliveries to Electric Utility Consumers
Gas Consumption: Lease and Plant Fuel	Tcf / yr	EIA (www.eia.doe.gov), *Natural Gas Monthly*, Table of Natural Gas Consumption in the United States, 1992-1997
Gas Consumption: Pipeline Fuel	Tcf / yr	EIA (www.eia.doe.gov), *Natural Gas Monthly*, Table of Natural Gas Consumption in the United States, 1992-1997
Gas Consumption: Transportation	Tcf / yr	NGA 1993 (1990-1992) & NGA97 (1993-two years before current year), Table 1 – Summary Statistics
Transmission Pipelines Length	Miles	American Gas Association, *Gas Facts*
Appalachia Wells	Wells	IPAA, *The Oil and Gas Producing Industry in Your State*
North Central Associated Wells	Wells	Calculated as 8.6% of oil wells reported in IPAA, *The Oil and Gas Producing Industry in Your State*
North Central Non-Associated Wells	Wells	IPAA, *The Oil and Gas Producing Industry in Your State*
Rest of U.S. Wells	Wells	IPAA, *The Oil and Gas Producing Industry in Your State*
Rest of U.S. Associated Wells	Wells	Calculated as 46.1% of oil wells reported in IPAA, *The Oil and Gas Producing Industry in Your State*
Appalachia, North Central (Non-Associated), and Rest of U.S.	Wells	Calculated using data for two years prior to 1997
Gulf of Mexico Off-Shore Platforms	Platforms	Minerals Management Service
Rest of U.S. Off-Shore Platforms	Platforms	May include platforms off the shore of Alaska, Minerals Management Service
North Central (Non-associated) and rest of U.S.	Wells	Calculated using data for two years prior to 1997
Number of Gas Plants	Plants	*Oil and Gas Journal*
Distribution Mains – Cast Iron	Mains	American Gas Association, *Gas Facts*
Distribution Mains – Unprotected Steel	Miles	American Gas Association, *Gas Facts*
Distribution Mains – Protected Steel	Miles	American Gas Association, *Gas Facts*
Distribution Mains – Plastic	Miles	American Gas Association, *Gas Facts*
Services – Unprotected Steel	Services	American Gas Association, *Gas Facts*
Services – Protected Steel	Services	American Gas Association, *Gas Facts*
Services – Plastic	Services	American Gas Association, *Gas Facts*
Services - Copper	Services	American Gas Association, *Gas Facts*

Exhibit III-3: Best Management Practices

Best Management Practice	Description
Replace or repair high bleed pneumatics devices with low bleed devices	High bleed rate pneumatic devices that employ gas to operate the actuators are ubiquitous in the industry and are a major source of emissions. Replacing them with low bleed devices where possible reduces emissions considerably.
Practice directed inspection and maintenance of compressor stations	Compressor stations have a vast number of pipes, valves, and other equipment that leaks. As with gate stations, a very few leaks account for the total volume of emissions. The same strategy applied to compressor stations will reduce the vast majority of emissions at a low cost.
Reduce glycol recirculation rates on glycol dehydrators	Glycol dehydrators remove water from gas at the wellhead. The glycol also absorbs methane, which is vented to the atmosphere when the glycol is regenerated, at a rate directly proportional to the glycol circulation rate. Glycol is often over-circulated. Proper circulation rates can achieve pipeline water content requirements and reduce methane emissions.
Install flash tanks on glycol dehydrators	Glycol dehydrators remove water from gas at the wellhead. The glycol also absorbs methane, which is vented to the atmosphere when the glycol is regenerated. Flash tanks capture 90 percent of the methane before it reaches the reboiler.
Install fuel gas retrofit systems on compressors to capture otherwise vented fuel when compressors are taken off-line	When compressors are not running and are taken “offline,” they are often purged of the gas in the compression chambers and isolated from the high-pressure pipeline with much leakage occurring at the isolation valves. Keeping the isolated compressor pressurized and bleeding off the gas into a fuel gas system reduces losses to the atmosphere.
Install static-seal compressor rod packing on reciprocating compressors	Compressor rod packing keeps gas from the compressor from escaping along the shaft into the compressor housing. Packing leaks are greater while compressors are off-line and remain pressurized. Static-packs clamp down on the compressor rod when compressors are idle to reduce leakage.
Install dry seal systems on centrifugal compressors	Centrifugal compressors have elaborate sealing systems to keep high-pressure gas in the compressor from escaping. Wet seal systems use high-pressure oil as the seal. The oil absorbs gas and which is vented when the sealing oil is circulated. Dry seal systems use high pressure air to establish a seal and avoid these losses.
Practice early replacement of rings and rods on centrifugal compressors	By using company-specific financial objectives and monitoring data, natural gas transmission companies can determine emission levels at which it is cost effective to replace rings and rods.
Practice directed inspection and maintenance of gate stations and surface facilities	Gate Stations are where high transmission pipeline pressures are dropped down to distribution system pressures; other surface facilities also regulate pipeline pressures. Emissions occur at the equipment, joints, valves at these facilities. A few stations and equipment types account for most of the emissions. Directed inspection and maintenance uses leak rate data and economic criteria to focus repairs on the costliest leaks.

Exhibit III-4: Partner-Reported Opportunities

Partner-Reported Opportunities	Description
Practice directed inspection and maintenance of production sites, processing sites, transmission pipelines and liquid natural gas stations	Emissions occur at the equipment, joints, valves at these facilities. Directed inspection and maintenance uses leak rate data and economic criteria to focus repairs on the costliest leaks.
Practice enhanced directed inspection and maintenance at production sites, surface facilities, storage wells, off-shore platforms and compressor stations	Enhanced DI&M is a more aggressive DI&M program that involves increased frequency of survey and repair. Enhanced DI&M costs more but also achieves greater savings by further reducing gas leaks.
Install electric starters on compressors	Compressor engines are often started using a blast of high-pressure natural gas. Electric starters can replace these gas starters and avoid methane emissions.
Install plunger lifts at production wells	As gas fields mature, fluids can accumulate in the wellbore and the weight of these fluids can impede gas production. Accumulated fluids can be removed by swabbing, soaping, or "blowing down" the well, but these operations often emit large volumes of methane to the atmosphere. A plunger lift allows fluids to be removed without emitting methane. The plunger acts as a bottom-hole plug, and the pressure of the reservoir builds and slowly lifts the plunger to the surface. As the plunger is lifted, the reservoir fluid above it is also lifted. Plunger lifts prolong well life, increase productivity and reduce methane emissions.
Use capture vessels for blowdowns at processing plants and other facilities	A capture vessel can be used during blowdowns to avoid venting methane to the atmosphere. The captured natural gas can be re-routed to pipelines or used on-site as fuel.
Install instrument air systems	Methane leaks from pneumatic devices can be avoided by installing instrument air systems which open and close valves using electricity instead of pressure from gas systems.
Use portable evacuation compressors for pipeline repairs	A portable compressor can be used to evacuate the gas in an area of blocked-off pipeline that is about to be repaired. This gas can be re-routed to the pipeline.
Install catalytic converter on compressor engines	A catalytic converter is an afterburner that reduces pollution from incomplete fuel combustion. Methane is combusted, and the energy from combustion is unused, so benefits are restricted to the value placed on reducing methane emissions.
Use electronic metering	Replacing old pneumatic-based meter runs at gate stations with electronic meters will reduce methane emissions.
Replace cast iron distribution mains with protected steel or plastic pipe	Cast iron and unprotected steel pipeline is replaced with materials less prone to corrosion and leaks.
Replace cast iron distribution services with protected steel or plastic pipe	Cast iron services are replaced with materials less prone to corrosion and leaks.

Exhibit III-5: Cost Analysis Data and Assumptions for Best Management Practices

Best Management Practice	Applicability and Emission Reductions	Costs	Break-Even Gas Price ($/MMBtu)
Replace high-bleed pneumatics with low-bleed pneumatics	Applicability: 50%-90% of pneumatic systems in the production and transmission sector Emission Reduction: 50%-90%; for all sectors, applicability and emission reductions are higher for high-bleed devices For the production sector, 6 cases were examined (low-med.-high bleed; intermittent & continuous) For the transmission sector, 9 cases were examined (low-med.-high bleed; continuous, turbine & displacement)	Capital: $750/device ($1,500 per device x 0.5 to reflect early replacement) Annual O&M: $150	$0.49-$18.00 for the production sector; break-even gas prices are lower for high-bleed devices $0.20-$318 for the transmission sector; break-even gas prices are lower for high-bleed devices
Practice directed inspection and maintenance at compressor stations	Applicability: 100% of compressor stations in the transmission sector Emission Reduction: 12%	Capital: $5,000/station instrument spread across 10 facilities yielding $500/facility Annual O&M: $2,065/station	$0.55 for storage compressor stations $0.61 for transmission compressor stations
Use static-seal compressor rod packing	Applicability: 100% of reciprocating compressors in the transmission sector Emission Reduction: 6.0% of emissions from storage compressor stations, 8.7% of emissions from transmission compressor stations	Capital: $3,000/compressor Annual O&M: none	$1.81 for storage compressor stations $1.74 for transmission compressor stations
Reduce glycol recirculation rates on dehydrators	Applicability: 100% of dehydrators in production, processing and transmission sector Emission Reduction: 30-60% of emissions from production and processing, 30% of emissions from transmission For the production and processing sectors, 4 cases were examined (with/ & without flash tanks; with & without pumps)	Capital: $0 Annual O&M: $50/dehydrator	$0.45 for dehydrators without flash tanks in the processing sector $50.64-$101 for dehydrators with flash tanks in the processing sector $0.16 for dehydrators without flash tanks in transmission sector $0.68 for dehydrators with flash tanks in transmission sector
Install flash tank separators on glycol dehydrators	Applicability: 100% of glycol dehydrators without flash tanks in the production, processing and transmission sectors Emission Reduction: For the production and processing sectors, 12%-63% of emissions from dehydrator vents and 63% of emissions from Kimray pumps; for the transmission sector, 90% of emissions from dehydrators with gas-assisted pumps, 30% of emissions from dehydrators without gas-assisted pumps	Capital: $8,000/dehydrator Annual O&M: None	$9.49 for dehydrators with gas assisted pumps and $232 for dehydrators without gas assisted pumps on dehydrator vents in the production and processing sectors $3.42 for transmission sector
Use fuel gas retrofits	Applicability: 100% of reciprocating compressors in the transmission sector Emission Reduction: 36% of emissions from reciprocating compressors in the transmission sector, 21.3% of emissions from reciprocating compressors in gas processing plants	Capital: $1,250/compressor Annual O&M: None	$0.12 for storage compressor stations $0.17 for transmission compressor stations $0.40 for processing compressor stations

Exhibit III-5: Cost Analysis Data and Assumptions for Best Management Practices (continued)

Best Management Practice	Applicability and Emission Reductions	Costs	Break-Even Gas Price ($/MMBtu)
Change wet seals to dry seals on centrifugal compressors	Applicability: 100% of all centrifugal comp. in the processing and transmission sectors Emission Reduction: 77.2% of emissions from storage comp., 70.9% of emissions from trans. comp. stations, 65.9% of emissions from processing comp.	Capital: $240,000/compressor Annual O&M: savings in material and labor relative to wet seals of $63,000/compressor	$1.91 for storage compressor stations $2.10 for transmission compressor stations $3.22 for processing compressor stations
Practice early replacement of rings and rods on reciprocating compressors	Applicability: 100% of reciprocating compressors in the transmission sector Emission Reduction: 1.4% of emissions from storage compressor stations, 1.5% of emissions from trans. compressor stations	Capital: $100/compressor Annual O&M: $120	$2.09 for storage compressor stations $2.66 for transmission compressor stations
Practice directed inspection and maintenance at gate stations and surface facilities	Applicability: For transmission sector, 100% of transmission co. interconnect meter and regulator stations; for distribution sector, 100% of high pressure stations, 50% of medium pressure stations, and 0% of low pressure stations Emission Reduction: For transmission sector, 33% of emissions; for distribution sector, 33% of emissions from high pressure, 25% of emissions from medium pressure stations	Capital: $5,000/survey instrument spread across 20 facilities yielding $250/station Annual O&M: $295/station	For transmission sector: $0.75 for transmission co. interconnect $320 for farm taps and direct sales For distribution sector: $0.69 for M&R >300 psi $1.74 for M&R 100-300 psi $96.58 for M&R <100 psi

Exhibit III-6: Cost Analysis Data and Assumptions for Partner-Reported Opportunities

Partner Reported Opportunity	Applicability and Emission Reductions	Costs	Break-Even Gas Price ($/MMBtu)
Practice directed inspection and maintenance at production sites	Applicability: 100% of non-associated gas wells, 100% of off-shore platforms, and 100% of pipeline leaks in the production sector Emission Reduction: 33% of emissions from non-associated gas wells, 33% of emissions from off-shore platforms, and 60% of emissions from pipeline leaks	Capital: $200/well, $6,000/off-shore platform, $100/mile of pipeline Annual O&M: $300/well, $2,000/off-shore platform, $150/mile of pipeline	$415 for eastern on-shore non-associated gas wells $81.14 for rest of U.S. gas wells $10.46 for Gulf of Mexico off-shore platforms $25.88 for rest of U.S. off-shore platforms $15.27 for pipeline leaks $15.10 for chemical injection pumps
Use enhanced directed inspection and maintenance at production sites	Applicability: 100% of non-associated gas wells in the production sector Emission Reduction: 50%	Capital: $500 Annual O&M: $700	$647 for eastern on-shore non-associated gas wells $126 for rest of U.S. gas wells
Use electric starter	Applicability: 100% of compressor starts in the production sector Emission Reduction: 75%	Capital: $20,000/compressor Annual O&M: $5,000/compressor	$1,536
Use plunger lift well	Applicability: 20% of Appalachia (all non-associated) and 20% of rest of U.S. on-shore wells in the production sector Emission Reduction: 20%	Capital: $2,500/well Annual O&M: $100/well	$1,330 for Appalachia wells $260 for rest of U.S. on-shore wells
Use surge vessel to capture blowdowns	Applicability: 100% of pipeline venting during routine maintenance and upsets in production, processing and transmission sector Emission Reduction: 50%	Capital: $100,000/vessel-compressor-station (unit depends on sector) Annual O&M: $2,000/unit	>$100,000 for vessel blowdowns in the production sector $13,576 for compressor blowdowns in the production sector $11.42 for processing $10.63 for transmission
Use portable evacuation compressors	Applicability: 90% of pipeline venting during routine maintenance and upsets in production and transmission sector Emission Reduction: 80%	Capital: $1,400/mile Annual O&M: $10/mile	$1,239 for production sector $12.10 for transmission sector
Install instrument air systems	Applicability: 50%-90% of pneumatic systems in the production and transmission sector Emission Reduction: 100% For pneumatic device vents in the production sector, 6 cases were examined (low-med.-high bleed; intermittent & continuous) For the transmission sector, 9 cases were examined (low-med.-high bleed; continuous, turbine & displacement); applicability is higher for high-bleed devices	Capital: $4,200 Annual O&M: various ($750 for pneumatic device vents in the production sector)	$4.66-$52.56 for pneumatic device vents in the production sector; break-even gas prices are lower for high-bleed devices $3.28-$893 for the transmission sector; break-even gas prices are lower for high-bleed devices
Practice directed inspection and maintenance at processing sites	Applicability: 100% of processing plants Emission Reduction: 33%	Capital: $1,000/plant Annual O&M: $2,000/plant	$2.39

Exhibit III-6: Cost Analysis Data and Assumptions for Partner-Reported Opportunities (continued)			
PRO	**Applicability and Emission Reductions**	**Costs**	**Break-Even Gas Price ($/MMBtu)**
Use catalytic converters on engine exhaust	Applicability: 75% of engines and turbines in the transmission sector (including LNG storage) Emission Reduction: 75%	Capital: $3,386/MM HP-Hr ($20,000/engine) Annual O&M: $168/MM HP-Hr ($1,000/engine)	$4.74-$29.53 for compressor exhaust (production) $5.35 for engines (transmission) $94.63 for turbines (transmission) $7.33 for engines (storage) $85.95 for turbines (storage) $10.56 for engines (LNG storage) $479 for turbines (LNG storage)
Practice directed inspection and maintenance at LNG stations	Applicability: 100% of LNG stations in transmission sector Emission Reduction: 60%	Capital: $500/station Annual O&M: $2,065/station	$1.87
Practice directed inspection and maintenance of trans. pipelines	Applicability: 100% of pipeline leaks in the transmission sector Emission Reduction: 60%	Capital: $100 Annual O&M: $150	$527
Use enhanced directed inspection and maintenance at compressor stations	Applicability: 100% of compressor stations in the transmission sector Emission Reduction: 26.5% of emissions from storage compressors, 18.9% of emissions from trans. compressor stations	Capital: $1,000/station Annual O&M: $6,000/station	$0.69 for storage compressor stations $1.11 for transmission compressor stations
Practice directed inspection and maintenance at storage wells	Applicability: 100% of storage wells in the transmission sector Emission Reduction: 33%	Capital: $200/well Annual O&M: $200/well	$18.54
Practice enhanced directed inspection and maintenance at storage wells	Applicability: 100% of storage wells in the transmission sector Emission Reduction: 50%	Capital: $300/well Annual O&M: $400/well	$23.14
Practice enhanced directed inspection and maintenance at gate stations and surface facilities	Applicability: 100% of gate stations and surface facilities in the distribution sector Emission Reduction: 30%-80% of emissions; higher pressure stations have greater emission reductions	Capital: $1,000/station Annual O&M: $1,000/station	$1.01 for M&R >300 psi $2.35 for M&R 100-300 psi $113 for M&R <100 psi
Use electronic metering	Applicability: 100% of trans. co. interconnect M&R stations in the transmission sector; 100% of meter and regulator stations at city gates in distribution sector Emission Reduction: 95%	Capital: $15,000/station Annual O&M: $2,500/station	$4.84 for the transmission sector For the distribution sector: $4.46 for M&R >300 psi $8.40 for M&R 100-300 psi $186 for M&R <100 psi

Exhibit III-6: Cost Analysis Data and Assumptions for Partner-Reported Opportunities (continued)

PRO	Applicability and Emission Reductions	Costs	Break-Even Gas Price ($/MMBtu)
Replace pipeline	Applicability: 100% of cast iron and unprotected steel mains in distribution sector Emission Reduction: 95%	Capital: $1,000,000/mile Annual O&M: $50/mile	$1,229 for cast iron pipeline $2,662 for unprotected steel pipeline
Replace services	Applicability: 100% of unprotected steel services in distribution sector Emission Reduction: 95%	Capital: $250,000/service Annual O&M: $50/service	$43,155 for unprotected steel services

Exhibit III-7: Schedule of Emission Reduction Options for 2010					
Number	Option	Break-Even Gas Price ($/MMBtu)	Base Gas Price Type[a]	Carbon Equivalent Value ($/TCE)	Incremental Emission Reduction (MMTCE/yr)
1	Practice directed inspection and maintenance at gate stations and surface facilities (Meter/Regulator stations > 300 psi)	$0.69	Citygate	($23.42)	0.23
2	Practice directed inspection and maintenance at gate stations and surface facilities (Reg. > 300 psi)	$0.77	Citygate	($22.72)	<0.01
3	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (Meter/Regulator stations > 300 psi)	$1.01	Citygate	($20.51)	0.56
4	Install fuel gas retrofit systems on compressors to capture otherwise vented fuel when compressors are taken off-line (storage compressor stations)	$0.12	Pipeline	($19.60)	0.42
5	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (Reg. > 300 psi)	$1.13	Citygate	($19.49)	0.33
6	Reduce glycol circulation rates in dehydrators (not applicable to Kimray pumps – this option applies to transmission sector dehydrators without flash tanks)	$0.16	Pipeline	($19.18)	0.01
7	Install fuel gas retrofit systems on compressors to capture otherwise vented fuel when compressors are taken off-line (transmission compressor stations)	$0.17	Pipeline	($19.06)	1.63
8	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, high-bleed, continuous-bleed pneumatic devices)	$0.20	Pipeline	($18.83)	0.59
9	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, medium-bleed, continuous-bleed pneumatic devices)	$0.50	Pipeline	($16.10)	0.39
10	Install fuel gas retrofit systems on compressors to capture otherwise vented fuel when compressors are taken off-line (processing compressor stations)	$0.40	Wellhead	($16.09)	0.43
11	Practice directed inspection and maintenance at storage compressor stations	$0.55	Pipeline	($15.69)	<0.01
12	Reduce glycol circulation rates in dehydrators (not applicable to Kimray pumps – this option applies to production sector dehydrators without flash tanks, with gas assisted pumps)	$0.45	Wellhead	($15.67)	0.28
13	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to production sector, high-bleed, continuous-bleed devices)	$0.49	Wellhead	($15.24)	0.98
14	Practice directed inspection and maintenance at transmission compressor stations	$0.61	Pipeline	($15.05)	<0.01
15	Reduce glycol circulation rates in dehydrators (not applicable to Kimray pumps – this option applies to transmission sector dehydrators with flash tanks)	$0.68	Pipeline	($14.45)	0.73
16	Enhanced Directed Inspection and Maintenance at storage compressor stations	$0.69	Pipeline	($14.40)	0.05
17	Practice directed inspection and maintenance at gate stations and surface facilities (Meter/Regulator stations 100-300 psi)	$1.74	Citygate	($13.90)	0.35
18	Practice directed inspection and maintenance at gate stations and surface facilities (trans. co. interconnect)	$0.75	Pipeline	($13.80)	0.14
19	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (trans. co. interconnect)	$1.10	Pipeline	($10.65)	0.20

Exhibit III-7: Schedule of Emission Reduction Options for 2010 (continued)					
Number	**Option**	**Break-Even Gas Price ($/MMBtu)**	**Base Gas Price Type[a]**	**Carbon Equivalent Value ($/TCE)**	**Incremental Emission Reduction (MMTCE/yr)**
20	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to production sector, high-bleed, intermittent-bleed devices)	$1.00	Wellhead	($10.64)	0.90
21	Practice enhanced directed inspection and maintenance at transmission compressor stations	$1.11	Wellhead	($10.57)	0.04
22	Reduce glycol circulation rates in dehydrators (not applicable to Kimray pumps – this option applies to production sector dehydrators without flash tanks)	$1.04	Wellhead	($10.28)	0.02
23	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to production sector, medium-bleed, continuous-bleed devices)	$1.23	Wellhead	($8.51)	0.65
24	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (Meter/Regulator stations 100-300 psi)	$2.35	Citygate	($8.38)	0.56
25	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, high-bleed, turbine devices)	$1.47	Pipeline	($7.26)	0.04
26	Use reciprocating compressor rod packing (Static-Pac, applies to transmission sector)	$1.74	Pipeline	($4.85)	0.39
27	Use reciprocating compressor rod packing systems (Static-Pac, applies to storage)	$1.81	Pipeline	($4.16)	0.06
28	Practice directed inspection and maintenance at LNG stations	$1.87	Pipeline	($3.62)	0.01
29	Install dry seals on centrifugal compressors (storage sector)	$1.91	Pipeline	($3.27)	0.12
30	Use reciprocating compressor rod packing systems (early replacement of rings and rods on storage sector reciprocating compressors)	$2.09	Pipeline	($1.61)	0.01
31	Install dry seals on reciprocating compressors (transmission sector)	$2.10	Pipeline	($1.55)	0.64
32	Practice directed inspection and maintenance at production and processing sites	$2.39	Pipeline	($0.34)	<0.01
33	Replace higher-bleed pneumatic devices with lower-bleed pneumatic devices (applies to production sector, medium-bleed, intermittent-bleed devices)	$2.50	Wellhead	$3.00	0.68
34	Use reciprocating compressor rod packing systems (early replacement of rings and rods on transmission sector reciprocating compressors)	$2.66	Pipeline	$3.51	0.07
35	Practice directed inspection and maintenance at gate stations and surface facilities (Reg. 100-300 psi)	$4.11	Citygate	$7.65	0.14
36	Install instrument air systems (in place of transmission sector, high-bleed, continuos bleed pneumatic devices)	$3.28	Wellhead	$9.57	0.23
37	Install dry seals on reciprocating compressors (processing sector)	$3.22	Pipeline	$9.16	0.45
38	Install flash tank separators on transmission sector glycol dehydrators	$3.42	Pipeline	$10.47	0.02
39	Use electronic metering (Meter/Regulator stations > 300 psi)	$4.46	Citygate	$10.86	0.10
40	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, low-bleed, continuous-bleed devices)	$3.60	Pipeline	$12.07	0.02

Exhibit III-7: Schedule of Emission Reduction Options for 2010 (continued)

Number	Option	Break-Even Gas Price ($/MMBtu)	Base Gas Price Type[a]	Carbon Equivalent Value ($/TCE)	Incremental Emission Reduction (MMTCE/yr)
41	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, medium-bleed, turbine devices)	$3.68	Pipeline	$12.80	0.02
42	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (Reg. 100-300 psi)	$5.54	Citygate	$20.69	0.22
43	Use catalytic converter (applies to compressor exhaust during normal operations in the production and processing sectors)	$4.74	NA	$20.99	<0.01
44	Install instrument air systems (in place of production sector, high-bleed, continuous-bleed pneumatic devices)	$4.66	Wellhead	$22.63	0.35
45	Install instrument air systems (in place of transmission sector, medium-bleed, continuous-bleed pneumatic devices)	$4.79	Pipeline	$22.90	0.14
46	Use electronic monitoring (trans. co. interconnect)	$4.84	Pipeline	$23.33	0.06
47	Use catalytic converter (applies to compressor exhaust during normal operations in the transmission sector)	$5.35	NA	$26.59	<0.01
48	Use catalytic converter (applies to storage engine compressor exhaust during normal operation of transmission sector)	$7.33	NA	$44.58	0.51
49	Install instrument air systems (in place of production sector, high-bleed, intermittent-bleed devices)	$7.21	Wellhead	$45.82	0.32
50	Use electronic monitoring (Meter/Regulator stations 100-300 psi)	$8.40	Citygate	$46.62	0.42
51	Use catalytic converter (applies to fugitive emissions from compressor exhaust in the production and processing sectors)	$8.27	NA	$53.13	0.77
52	Install instrument air systems (in place of production sector, medium-bleed, continuous-bleed pneumatic devices)	$8.39	Wellhead	$56.58	0.24
53	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to production sector, low-bleed, continuous-bleed devices)	$8.89	Wellhead	$61.09	0.02
54	Install flash tank separators on production-sector dehydrators with gas-assisted pumps	$9.49	Wellhead	$66.58	<0.01
55	Install instrument air systems (in place of production sector, high-bleed, turbine devices)	$9.68	Pipeline	$67.43	<0.01
56	Practice directed inspection and maintenance on Gulf of Mexico off-shore platforms	$10.46	Wellhead	$73.04	<0.01
57	Use catalytic converter (applies to LNG compressor exhaust)	$10.56	NA	$73.90	<0.01
58	Use portable evacuation compressors (applies to transmission sector station venting)	$10.63	Pipeline	$74.61	<0.01
59	Use surge vessels (applies to storage sector station venting)	$10.63	Pipeline	$74.61	<0.01
60	Use surge vessels (applies to LNG station venting)	$10.63	Pipeline	$74.61	<0.01
61	Use surge vessels (applies to blowdowns/venting in the production sector)	$11.42	Pipeline	$81.73	1.14
62	Use surge vessels (applies to pipeline venting during routine maintenance in the transmission sector)	$12.10	Pipeline	$87.98	0.18
63	Install instrument air systems (in place of transmission sector, low-bleed, continuous-bleed devices)	$12.34	Pipeline	$92.60	0.78

Exhibit III-7: Schedule of Emission Reduction Options for 2010 (continued)					
Number	**Option**	**Break-Even Gas Price ($/MMBtu)**	**Base Gas Price Type[a]**	**Carbon Equivalent Value ($/TCE)**	**Incremental Emission Reduction (MMTCE/yr)**
64	Install instrument air systems (in place of production sector, medium-bleed, intermittent-bleed devices)	$14.77	Wellhead	$115	0.22
65	Practice directed inspection and maintenance (applies to chemical injection pumps)	$15.10	Wellhead	$115	<0.01
66	Practice directed inspection and maintenance (applies to pipeline leaks)	$15.27	Wellhead	$117	<0.01
67	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, high-bleed, displacement devices)	$17.67	Pipeline	$140	0.56
68	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to production sector, low-bleed, intermittent-bleed devices)	$18.00	Wellhead	$144	0.01
69	Practice directed inspection and maintenance at storage wells	$18.54	Pipeline	$147	<0.01
70	Install instrument air systems (in place of transmission sector, medium-bleed, turbine devices)	$20.81	Pipeline	$169	0.04
71	Practice enhanced directed inspection and maintenance at storage wells	$23.14	Pipeline	$188	<0.01
72	Practice directed inspection and maintenance at production sites	$25.88	Wellhead	$213	0.02
73	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, low-bleed, turbine devices)	$26.48	Pipeline	$220	<0.01
74	Install instrument air systems (in place of production sector, low-bleed, continuous-bleed devices)	$27.06	Wellhead	$226	0.04
75	Use catalytic converters on compressor exhaust during normal operations in the production and processing sector	$29.53	NA	$246	<0.01
76	Practice directed inspection and maintenance at surface facilities (applies to Reg. 40-100 psi.)	$40.03	Citygate	$334	0.02
77	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, medium-bleed, displacement devices)	$44.18	Pipeline	$381	<0.01
78	Practice enhanced directed inspection and maintenance at surface facilities (applies to Reg. 40-100 psi.)	$46.78	Citygate	$396	0.01
79	Reduce the recirculation rate on production sector glycol dehydrators with flash tanks with gas assisted pumps	$50.64	Wellhead	$441	<0.01
80	Install instrument air systems (in place of production sector, low-bleed, intermittent-bleed devices)	$52.56	Wellhead	$458	<0.01
81	Install instrument air systems (in place of transmission sector, low-bleed, turbine devices)	$76.41	Pipeline	$674	<0.01
82	Practice directed inspection and maintenance at U.S. gas wells on-shore	$81.14	Wellhead	$716	<0.01
83	Use catalytic converters on compressor exhaust (applies to turbine engines in the storage sector)	$85.95	NA	$760	<0.01
84	Install instrument air systems (in place of transmission sector, high-bleed, displacement devices)	$91.34	Pipeline	$810	<0.01

Exhibit III-7: Schedule of Emission Reduction Options for 2010 (continued)

Number	Option	Break-Even Gas Price ($/MMBtu)	Base Gas Price Type[a]	Carbon Equivalent Value ($/TCE)	Incremental Emission Reduction (MMTCE/yr)
85	Use catalytic converters on compressor exhaust (applies to turbine engines in the transmission sector)	$94.63	NA	$838	<0.01
86	Practice directed inspection and maintenance at gate stations and surface facilities (applies to Meter and Regulator stations < 100 psi)	$96.58	Citygate	$849	<0.01
87	Reduce the recirculation rate on production sector glycol dehydrators with flash tanks without gas assisted pumps	$101	Wellhead	$901	<0.01
88	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (applies to Meter and Regulator stations < 100 psi)	$113	Citygate	$997	<0.01
89	Practice enhanced directed inspection and maintenance at U.S. gas wells on-shore	$126	Wellhead	$1,127	<0.01
90	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (R-vault > 300 psi)	$140	Citygate	$1,247	<0.01
91	Use electronic monitoring (Meter/Regulator stations < 100 psi)	$186	Citygate	$1,664	<0.01
92	Install instrument air systems (in place of transmission sector, medium-bleed, displacement devices)	$225	Pipeline	$2,025	<0.01
93	Install flash tank separators on production-sector glycol dehydrators without gas-assisted pumps	$232	Wellhead	$2,087	<0.01
94	Use plunger lift well (applies to U.S. on-shore wells)	$260	Wellhead	$2,341	<0.01
95	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, low-bleed, displacement devices)	$318	Pipeline	$2,872	<0.01
96	Practice directed inspection and maintenance at gate stations and surface facilities (R-vault > 300 psi)	$320	Citygate	$2,882	<0.01
97	Practice directed inspection and maintenance at gate stations and surface facilities (M&R Farm Taps + Direct Sales)	$320	Pipeline	$2,891	<0.01
98	Practice directed inspection and maintenance at production sites (Eastern on-shore, Appalachia non-associated gas wells)	$415	Wellhead	$3,755	<0.01
99	Practice directed inspection and maintenance at production sites (Eastern on-shore north central non-associated gas wells)	$415	Wellhead	$3,755	<0.01
100	Use catalytic converters on compressor exhaust (applies to LNG compressor emissions from turbine engines)	$479	NA	$4,337	<0.01
101	Practice directed inspection and maintenance at transmission pipelines	$527	Pipeline	$4,771	<0.01
102	Practice enhanced directed inspection and maintenance at production sites (Eastern on-shore, Appalachia non-associated gas wells)	$647	Wellhead	$5,860	<0.01
103	Practice enhanced directed inspection and maintenance at production sites (Eastern on-shore north central non-associated gas wells)	$646	Wellhead	$5,860	<0.01
104	Install instrument air systems (in place of transmission sector, low-bleed, displacement devices)	$893	Pipeline	$8,100	<0.01
105	Practice directed inspection and maintenance at wells and other similar facilities (applies to cast-iron mains)	$1,229	Citygate	$11,155	<0.01

Exhibit III-7: Schedule of Emission Reduction Options for 2010 (continued)

Number	Option	Break-Even Gas Price ($/MMBtu)	Base Gas Price Type[a]	Carbon Equivalent Value ($/TCE)	Incremental Emission Reduction (MMTCE/yr)
106	Use portable evacuation compressors (applies to production sector pipeline blowdowns)	$1,240	Wellhead	$11,253	<0.01
107	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (R-vault 100-300 psi)	$1,248	Citygate	$11,315	<0.01
108	Use plunger-lift wells (applies to Eastern on-shore, Appalachia non-associated gas wells)	$1,330	Wellhead	$12,075	<0.01
109	Use electric starter (applies to compressor starts in the production and processing sector)	$1,536	Wellhead	$13,942	<0.01
110	Practice directed inspection and maintenance at gate stations and surface facilities (R-vault 100-300 psi)	$2,313	Citygate	$21,002	<0.01
111	Practice directed inspection and maintenance at wells and other similar facilities (applies to unprotected steel mains)	$2,662	Citygate	$24,190	<0.01
112	Practice directed inspection and maintenance at gate stations and surface facilities (Reg. < 40 psi)	$3,130	Citygate	$28,434	<0.01
113	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (Reg. < 40 psi)	$3,658	Citygate	$33,238	<0.01
114	Practice directed inspection and maintenance at gate stations and surface facilities (R-vault 40-100 psi)	$4,813	Citygate	$43,735	<0.01
115	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (R-vault 40-100 psi)	$5,625	Citygate	$51,122	<0.01
116	Use surge vessels to capture gas during compressor blowdowns in the production sector	$13,576	Wellhead	$123,433	<0.01
117	Practice directed inspection and maintenance in the transmission sector (replace unprotected steel services)	$43,155	Citygate	$392,423	<0.01
118	Use surge vessels to capture gas during vessel blowdowns in the production sector	$656,849	Wellhead	$5,973,306	<0.01

[a] Wellhead = $2.17/MMBtu, pipeline = $2.27/MMBtu, citygate = $3.27/MMBtu.
All prices are in real 1996 dollars.

Reference

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