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Project Summary

Methane Emissions from the Natural Gas Industry

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Gas Research Institute (GRI) and the U.S. Environmental Protection Agency's (EPA's) Office of Research and Development cofunded a major study to quantify methane emissions from U.S. natural gas operations. For the 1992 base year, total methane emissions were estimated at 314 ± 105 Bscf (6.04 ± 2.01 Tg), which is equivalent to 1.4% ± 0.5% of gross natural gas production.

Since 1992, many companies have participated in voluntary programs designed to reduce emissions. Methane emission reductions from these programs are not reflected in the report. However, methane emissions from a future incremental increase in gas sales were evaluated. Depending on the size of the potential increase in sales, estimated emissions would be between 0.5% and 1.0% of the incremental increase.

This study provides data from the U.S. natural gas industry needed for constructing global methane inventories and for determining the relative impacts of coal, oil, and natural gas use on global warming. Using this study's emissions estimate and some key assumptions, an analysis showed that the impact on warming from the use of oil and coal per unit of energy generated is much larger than that from the use of natural gas.

This study is documented in 15 volumes. Volume 2 is a technical summary that includes what was done and how the measurements and calculations were performed.

This Project Summary was developed by EPA's National Risk Management Research Laboratory's Air Pollution Prevention and Control Division, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in 15 volumes comprising a report of the same title (see Project Report ordering information at back).

Introduction

This report summarizes a major study conducted by GRI and EPA to quantify methane emissions from U.S. natural gas operations. The goal was to determine these emissions to within ± 0.5% of natural gas production, starting at the wellhead and ending immediately downstream of the customer's meter. The study was conducted because this information is needed to determine if natural gas can be used as an integral part of a fuel switching strategy to reduce the potential of global warming, and to provide data for a global methane inventory.

Carbon dioxide (CO_2) contributes nearly as much to global warming as all other greenhouse gases combined. Since natural gas produces much less CO_2 per unit of energy when combusted than either coal or oil, the Intergovernmental Panel on Climate Change (IPCC), EPA, and others have suggested that, by promoting the increased use of natural gas, global warming could be reduced. However, methane, which is the major constituent of natural gas, is also an important greenhouse gas and, on a weight basis, methane is a more potent greenhouse gas than CO_2. For this reason, it was important to determine if emissions from the natural gas industry are large enough to substantially reduce or even eliminate the advantage that natural gas has because of its much lower CO_2 emissions during combustion.

This study, like other efforts to develop emission inventories, had to address several difficult problems. Most of these problems were primarily associated with the size and diversity of the natural gas industry and the number of sources that must be considered. This industry complexity, combined with the lack of both equipment populations and methods for estimating emissions, meant that early in the program, resources were devoted to developing comprehensive methods for estimating and extrapolating emissions. This also included selecting an accuracy goal that could reasonably be achieved but was sufficiently accurate to examine the fuel switching strategy.

Considering these issues, a method of approach was developed that

- Accounted for all emission sources;
- Measured and calculated emissions;
- Extrapolated emissions data; and
- Assessed the accuracy of the final estimate.

Method for Estimating Emissions

This summary briefly describes the method used to estimate methane emissions from the natural gas industry.

Accounting for All Emission Sources

The natural gas industry (shown in Figure 1) was divided into four segments: production, processing, transmission/storage, and distribution. The project established boundaries for each industry segment to specify the equipment included in the study. The guideline used for setting the boundary was to include only the equipment in each segment that is required for *marketing* natural gas.

To fully characterize the natural gas industry and account for all potential sources of methane, the four industry segments were divided into facilities, equipment, and components; and emission sources were identified by equipment type, mode of operation, and type of emission. Equipment types included individual devices, such as a pneumatic operator; large pieces of equipment, such as a compressors; or a grouping of equipment, such as an offshore platform. Modes of operation are start-up, normal operations, maintenance, upsets, and mishaps. Emission types are fugitive, vented, and combustion.

For this project each emission source was accounted for by carefully examining the operating mode for each equipment category. This differentiation ensured that all emission sources were accounted for and that all types of emissions from the source were considered. For example, compressor engines can be a significant source of fugitive, vented, and combustion emissions that result from a variety of operating modes. During normal operations, unburned methane is emitted in the

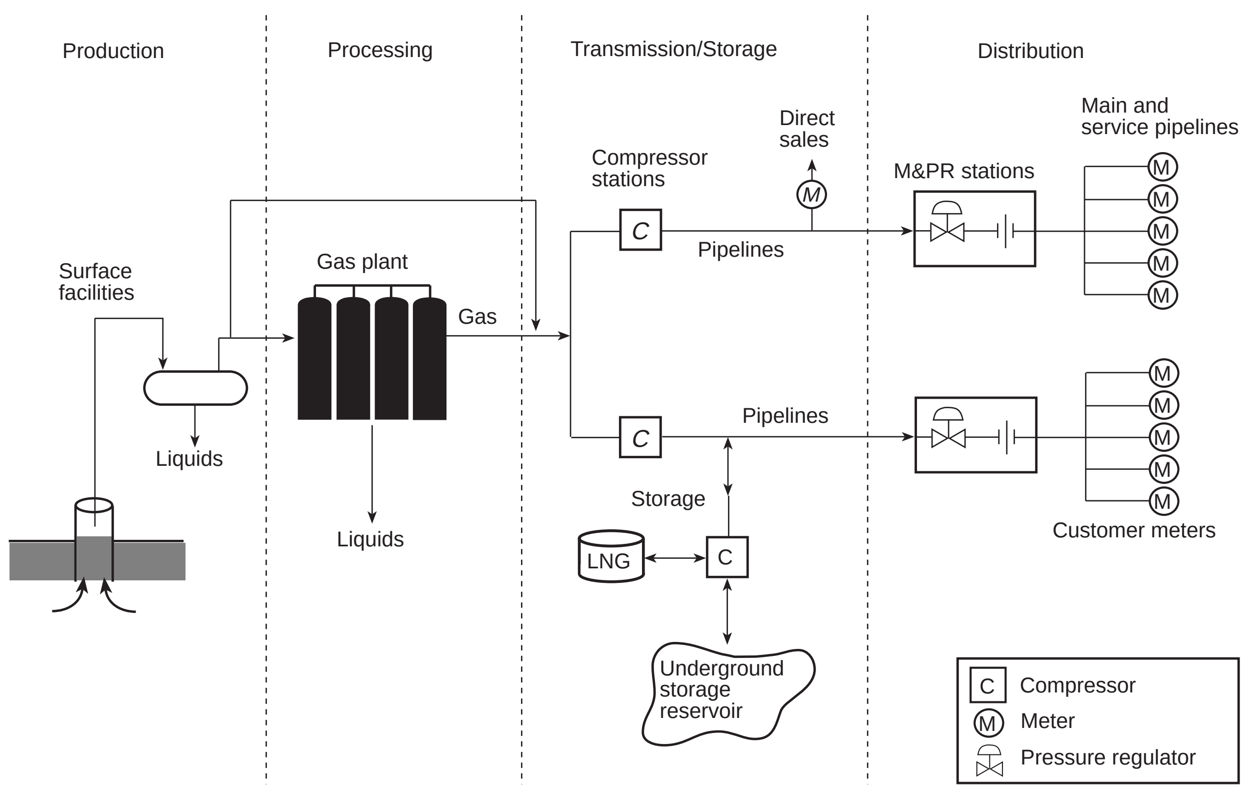

Figure 1. Gas industry flow chart.

engine exhaust, and fugitive emissions can result from leaks in valves and pressurized connections. Also, natural gas is vented during engine start-ups if natural gas is used to power the starter turbine. During upsets, natural gas is released from compressor blowdown and pressure relief valves, and natural gas is vented during compressor blowdown for maintenance.

Measuring and Calculating Emissions

Initially, few methods were available for measuring and/or calculating emissions from natural gas facilities. Therefore, the early stages of this study were spent developing measurement techniques and demonstrating them in the field before using them to gather data for the study. On the basis of these proof-of-concept tests, three measurement methods were eventually chosen for use in this study. For pipeline leaks, the emission rate was measured by isolating the leaking section of pipe and measuring the amount of gas needed to maintain operating pressure in the line. For fugitive leaks from aboveground facilities, either a tracer gas method or a component emission factor approach was used.

For the tracer gas method, a tracer gas such as sulfur hexafluoride is released at a known constant rate near the methane source. The emission rate was determined by measuring the concentration of the tracer and methane downwind; since the ratio of emission rates is equal to the ratio of concentrations, the methane emission rate can be calculated.

The component emission measurement approach develops average emission rates for the basic components (valves, flanges, seals, and other pipe fittings) that comprise natural gas facilities. The total emissions from the facility are the product of the number of components times the corresponding emission factor.

New component emission factors were developed as a result of this study for natural gas production and processing facilities, compressor stations, and residential and commercial meters. Also a new “Hi-Flow” instrument was developed that can measure emissions quickly and accurately from pneumatic control devices, valves, flanges, and other pipe fittings.

In some cases it is more accurate and less complicated to calculate, rather than measure, emissions. An example is emissions from a “blowdown” to make a pipe repair. Knowing the temperature and pressure of the gas, the volume of the pipe, and the frequency of the event, emissions can be calculated. Another reason for calculating emissions is that it may not be practical to measure emissions from some sources. Since annual emissions are needed for the study, it is not practical to try to measure highly variable, unsteady emissions. In developing engineering models for calculating these types of emissions, it is necessary to first understand the equipment and the nature of the process causing the emissions and then to collect field data on the frequency of the event.

Extrapolating Emissions

A considerable amount of field data was collected during this study. In addition to measuring emissions and collecting information on operating characteristics of equipment and frequency of events, a substantial effort was required to collect information on equipment populations. Equipment counts are needed to extrapolate measured and calculated emissions to other similar sources in the industry.

Data were collected on each source category identified during initial stages of the project. However, because of the large number of sources in each source category, data were collected on a relatively small percentage of all sources in each category. Therefore, these data had to be extrapolated to account for the sources that were not measured in order to develop a national emissions estimate. To extrapolate the emission data, emission and activity factors were defined so that their product equals the annual nationwide emissions from a given source category. Typically, the emission factor is defined as the average annual emissions from a piece of equipment or event. The activity factor would then be the national population (i.e., the total equipment count or total number of events). For example, if fugitive emissions from compressor engines is the source category, then average emissions per engine would be the emission factor, and the number of engines would be the activity factor.

Although this approach is straightforward, the application proved to be difficult due to the lack of data on equipment populations and operational events. Limited information is available on a national basis. Collecting data on activity factors, e.g., number of separators, pneumatic control devices, miles of gathering lines, blowdown events, required a large number of site visits and was therefore a major part of the study.

Assessing Accuracy

The accuracy of the emissions estimate depends on the precision and bias of both the activity and emission factors. In developing activity factors, as in conducting emission measurements, care was taken in developing sampling protocols, detecting and eliminating bias, and developing methods for calculating precision.

The accuracy goal of the project was to determine emissions from the natural gas industry to within $\pm$ 0.5% of gross natural gas production. This goal was established based on the accuracy needed for constructing emission inventories for use in global climate change models and for assessing the validity of the proposed fuel switching strategy.

The first step in achieving the accuracy goal was to develop accuracy targets for each source category. Accuracy targets were assigned so that a higher degree of accuracy would be required for the largest sources while achieving the overall program goal. This had the additional advantage of automatically assigning more program resources to the most important source categories.

Accuracy is made up of precision and bias. Precision can be calculated, but bias can only be minimized. To minimize bias, a sampling approach similar to disproportionate stratified random sampling was developed. A project review committee was established and industry advisory groups were formed for production, transmission, and distribution to review the program and ensure that any potential for bias was identified and eliminated. Also the data were analyzed to ensure that data were not sampled disproportionately with respect to the parameters that had a large impact on emissions. This not only minimized bias but also reduced the impact that outlying data points had on the result. The precision of the activity and emission factors was calculated for a 90% confidence level from the number of data points collected and the standard deviation. The precision of the emission estimate for each source category as well as the national estimate was also calculated in a statistically rigorous fashion.

Results

1992 Baseline Emissions

Total methane emissions from the natural gas industry for the 1992 baseline year are 314 $\pm$ 105 Bscf (6.04 $\pm$ 2.01 Tg). This is approximately 1.4% $\pm$ 0.5% of gross natural gas production, a result that meets the project accuracy goal. This represents approximately 19% of total U.S. anthropogenic emissions, based on methane emission estimates reported by the EPA for major anthropogenic sources (see Figure 2).

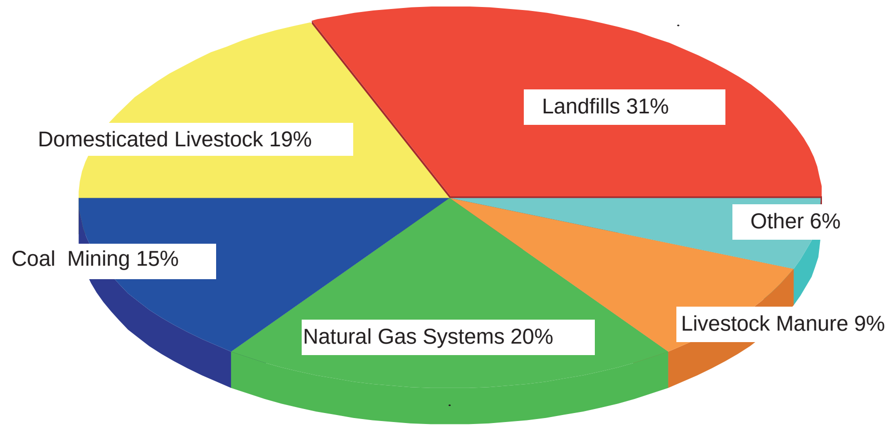

Figure 2. Contribution of major methane sources to total U.S. anthropogenic emissions.

Figure 3 presents methane emissions for the natural gas industry by industry segment. The transmission/storage segment accounts for the largest portion of emissions (37%) with the processing segment contributing the least (12%).

The largest emission sources for each industry segment are presented in Table 1. Fugitive emissions are the largest contributor to methane emissions from natural gas processing, transmission, and storage. Nearly 90% of these emissions result from leaks on compressor components such as the suction, discharge, blowdown, and pressure regulator valves and compressor seals. Fugitive emissions from all compressor components are approximately 80 Bscf (1.6 Tg), while fugitive emissions from all other compressor station components, such as yard piping and filter-separators, are approximately 10 Bscf (0.19 Tg). Compressor engine exhausts are responsible for slightly more than 25 Bscf (0.48 Tg) of methane emissions.

Fugitive emissions from pipelines are approximately 48 Bscf (0.93 Tg), of which 42 Bscf (0.80 Tg) is from distribution piping. Distribution piping systems actually emit 51 Bscf (0.98 Tg), but approximately 18% of the natural gas leaked is oxidized in the soil by methanotrophs. Approximately 22 Bscf (0.42 Tg) is leaked from cast iron mains that constitute only 6% of the total length of distribution main pipelines. However, most cast iron leaks are very small and, since the oxidation rate varies inversely with leak rate, only 60% of the leaks (13 Bscf or 0.25 Tg) reach the surface.

The two largest methane emission sources in natural gas production are pneumatic control devices and fugitives. Prior to this study, pneumatic devices were not considered a major emission source. Approximately a third of these devices bleed natural gas to the atmosphere continuously. Pneumatic devices are the largest source of methane emissions in the production segment, accounting for 31 Bscf (0.60 Tg). Total fugitive emissions from production equipment are large even though the average leak rate is small, because of the large number (approximately 80 million) of valves, connectors, and other pipe fittings on equipment located at production sites across the country.

Emissions from Incremental Increases in Gas Sales

Consumption of natural gas has increased since the 1992 base year. To determine the effect that this increase and future increases will have on emissions, a study was conducted to determine the percent increase in emissions resulting from an incremental increase in natural gas production and sales. The study found that increases in throughput would, in many cases, produce increases in emissions. However, the average increase in emissions would be proportionally smaller than the increase in system throughput.

The study examined the consequences of increasing gas sales by 5%, 15%, and 30% under three scenarios: uniform, winter peak, and summer peak load profiles. All segments of the gas industry were examined to determine the percent increase in equipment that would be needed to meet the increased demand. The percent increase in emissions was then estimated based on changes in the current system that would be required to accommodate the increase in gas sales. The GRI/EPA emission estimate was used to calculate the percent increase in emissions that would result from an incremental increase in natural gas sales for several scenarios examined in the study.

The most realistic scenario assumed that the system would be expanded using the latest technologies, whereas the most conservative scenario assumes that the expanded system mirrors the existing system. Generally, as the system expands, the emission rate for the expansion would be less, as a percent of throughput, than for the base system. Emissions from a system load increase (an increase in consumption of gas) of 30% would emit at only one- to two-thirds of the base emission rate. For example, if gas production increased by 30% (6 to 7 trillion cubic feet per year), emissions from the system expansion would be between 30 and 70

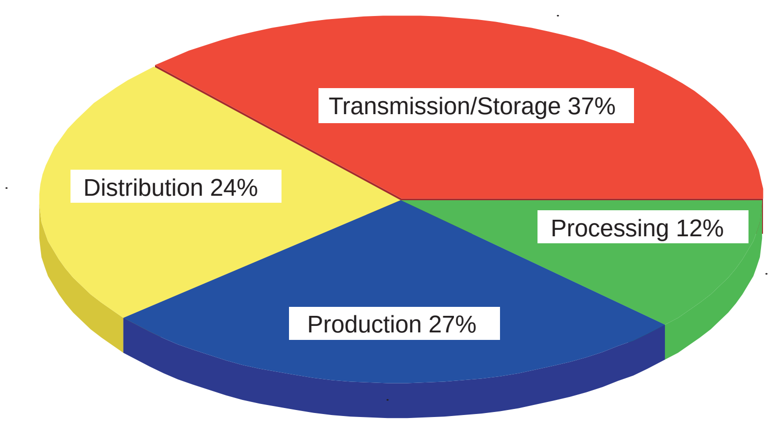

Figure 3. Summary of methane emissions.

Table 1. Largest Emission Sources by Industry Segment

Segment	Source	Annual Methane Emissions (Bscf)	(Tg)	Percent of Segment Total
Production	Pneumatic devices	31	0.60	37
	Fugitive emissions	17	0.33	21
	Dehydrators	14	0.28	17
	Other	21	0.41	25
Processing	Fugitive emissions	24	0.47	67
	Compressor exhaust	7	0.13	19
	Other	5	0.10	14
Transmission/ Storage	Fugitive emissions	68	1.30	58
	Blow and purge	19	0.36	16
	Pneumatic devices	14	0.27	12
	Compressor exhaust	11	0.22	10
	Other	5	0.10	4
Distribution	Underground pipeline leaks	42	0.80	54
	Meter and pressure regulating stations	27	0.53	35
	Customer meters	6	0.11	8
	Other	2	0.04	3
Total[1]		**314 Bscf**	**6.04 Tg**	

[1] Individual sources may not sum exactly to total shown due to roundoff errors.

Bscf. These emissions, when divided by the incremental production, are equivalent to an emission rate between 0.4% and 1.0% of incremental production. This is much lower than the 1.4% of production emitted from the current base system for 1992.

Emissions are lower for an incremental increase in gas sales because the current system has excess capacity and any additional equipment that would have to be installed to meet increased demand would use current and lower emitting technology. A few examples of these technologies are no-bleed pneumatic devices, turbine compressor engines, and plastic pipe instead of steel and cast iron mains.

Emissions and Fuel Switching

The estimate of methane emissions from natural gas operations was used in an analysis to determine if the potential for global warming could be reduced by switching from coal or oil to natural gas. Emissions from coal and oil were estimated from other sources. Other than CO_2 and methane, emissions from other greenhouse gases from the fuel cycle of fossil fuels are negligible. Methane, however is a more potent greenhouse gas than CO_2. The approach used was to determine the emissions of methane and CO_2 for the complete fuel cycle of natural gas, oil, and coal, and to convert the methane emissions to equivalent CO_2 using the Global Warming Potential (GWP).

The GWP is an index that relates the impact of releasing quantities of the various greenhouse gases to the release of an amount of CO_2 that would produce the same impact on global warming. Currently, there is a great deal of uncertainty in the time period associated with the GWP of methane. Typical time periods range from 50 to 500 years, which correspond to GWP values of 34 and 6.5, respectively. This means that 1 lb of methane is equivalent to between 6.5 and 30 lb of CO_2.

Equivalent CO_2 emissions from the fuel cycle of natural gas were calculated to be 132 lb/10^6 Btu (57 kg/GJ) for a GWP of 6.5 and 152 lb/10^6 Btu (66 kg/MJ) for a GWP of 34. Even for a GWP of 34, the analysis showed that, compared to natural gas, oil has 1.2 times the impact on global warming and coal has 1.5 times the impact.

Conclusions

Based on data collected, methane emissions from natural gas operations are estimated to be 314 ± 105 Bscf (6.04 ± 2.01 Tg) for the 1992 baseline year. This is approximately 1.4% ± 0.5% of gross natural gas production. This study also determined that the percentage of methane emitted per gas production rate for an incremental increase in natural gas sales would be between 1.19% and 1.38% of the total gas production, compared to 1.4% of production for the baseline case.

Results from this study were used to compare greenhouse gas emissions from the fuel cycle for natural gas, oil, and coal using the GWPs recently published by the IPCC. The analysis showed that natural gas contributes significantly less to global warming per unit of energy than coal or oil, which supports the fuel switching strategy suggested by IPCC and others.

This study, like other efforts in developing emission inventories, had to address the following typical but nevertheless difficult problems:

- Collecting demographic information;
- Developing methods for measuring and calculating emissions;
- Extrapolating a limited amount of data to a large, diverse national population; and
- Determining the accuracy of the final estimates.

The most difficult of these is evaluating the accuracy. Accuracy targets were established for each source category that would be needed to achieve the overall accuracy goal of the study. A sampling procedure with checks for bias was then established, data were collected, and the precision of the emission estimate was rigorously calculated for each category, as well as for the national estimate.

During the course of the study, equipment population in the gas industry was collected and new methods were developed for measuring emissions from a variety of sources. Unique methods were developed using tracer gas techniques, and a new “Hi-Flow” instrument was developed that provides a quick, cost-effective method for measuring the leak rate of valves, seals, pneumatic devices, and connectors.

In addition, results from this study are being used by the natural gas industry to reduce operating costs while reducing emissions. Some companies are also participating in the Natural Gas-Star program, a voluntary program sponsored by EPA’s Office of Air and Radiation in cooperation with the American Gas Association to implement cost-effective emission reductions and to report reductions to the EPA. Since this program was begun after the 1992 baseline year, any reductions in methane emissions from this program are not reflected in this study’s total emissions.

In conclusion, the project reached its accuracy goal and provides an accurate estimate of methane emissions for 1992 gas industry practices. The results can be used to construct U.S. methane inventories and analyze fuel switching strategies.

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***David A. Kirchgessner** is the EPA Project Officer (see below).*
The complete report, consisting of 15 volumes, is titled "Methane Emissions from the Natural Gas Industry" and has the following order numbers and costs:
The set (Order No. PB97-142913; Cost: $331.00, subject to change)
Volume 1: Executive Summary (Order No. PB97-142921; Cost: $19.50, subject to change)
Volume 2: Technical Report (Order No. PB97-142939; Cost: $31.00, subject to change)
Volume 3: General Methodology (Order No. PB97-142947; Cost: $38.00, subject to change)
Volume 4: Statistical Methodology (Order No. PB97-142954; Cost: $31.00, subject to change)
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