ESTIMATE OF METHANE EMISSIONS
FROM THE U.S. NATURAL GAS INDUSTRY

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ABSTRACT

Global methane emissions from the fossil fuel industries have been poorly quantified and, in many cases, emissions are not well-known even at the country level. Historically, methane emissions from the U.S. gas industry have been based on sparse data, incorrect assumptions, or both. As a result, the estimate of the contribution these emissions make to the global methane inventory could be inaccurate. For this reason the assertion that global warming could be reduced by replacing coal and oil fuels with natural gas could not be defended. A recently completed, multi year study conducted by the U.S. Environmental Protection Agency's Office of Research and Development and the Gas Research Institute had the objective of determining methane emissions from the U.S. gas industry with an accuracy of ± 0.5% of production. The study concluded that, in the 1992 base year, methane emissions from the industry were 314 ± 105 Billion standard cubic feet (Bscf) or 6.04 ± 2.01 Teragrams (Tg) (all conversions to international units are made at 15.56EC and 101.325 kPa).

1.0 INTRODUCTION

The Environmental Protection Agency [1] and the Intergovernmental Panel on Climate Change [2] have suggested that switching from coal and oil to natural gas fuels could serve as an interim measure to reduce the effects of global climate change caused by greenhouse gas emissions. Carbon dioxide is the most abundant greenhouse gas from anthropogenic sources and, in the U.S., 98.5 % of this contribution comes from the burning of fossil fuels. [3] The fuel-switching strategy was suggested because natural gas emits less carbon dioxide per unit of energy generated and because carbon dioxide contributes more to global warming than all other greenhouse gases combined. Because of the poor quality of methane emission estimates available however, it was not known if methane leakage and emissions from natural gas industry operations were large enough to substantially reduce or even eliminate the benefits of the lower carbon dioxide emissions. Our purpose in conducting this study was to improve the methane emission estimate for the U.S. gas industry to help evaluate this strategy and to generally improve the quality of the global methane inventory for modelers and policy makers. In this paper we describe the data gathering, statistical, and extrapolation procedures employed to derive the emission estimate but, while the results reflect favorably on the fuel-switching strategy, we do not discuss the separate analysis performed to support that evaluation.

2.0 BACKGROUND

Numerous estimates of methane emissions for the natural gas industry are available. Global emissions estimates from as long ago as 25 years have been produced, primarily for the purpose of determining global balances of atmospheric trace gases, but more recently for assessing global climate change issues. Estimates of global emissions from the natural gas industry are summarized in Table 1. Most of the commonly cited estimates range from 25 to 50 Tg/yr and assume leakage rates from 1 to 4 percent. Ehhalt and Schmidt's [6] as well as Hitchcock and Wechsler's [4] low estimates are exceptions but are explained by their use of an early base year in which production was lower. Darmstadter et al. [10] also produced a low estimate of 10 Tg/yr as a result of using a low assumed leakage rate of 1%. Keeling [5] assumed an exceptionally high leakage rate of 6 to 10 % to arrive at an estimate of 40 to 70 Tg/yr. Those estimates at the high end of the normal range usually result from the addition of emissions from venting and flaring. In the work by Sheppard et al. [7], Blake [8], and Cicerone and Oremland [13], it can be inferred from their discussions that the venting and flaring emissions are estimated for both oil and gas fields. The emissions are not separated by industry, however, and topics such as flaring efficiencies and venting versus flaring practices of individual countries are not addressed.

While it is not always explicitly stated in the literature, the leakage rates assumed appear to fall into the category known in the gas industry as UAG (unaccounted for gas). UAG is the difference between the volume of gas that a utility reports as purchased and the volume sold, less any company use or interchange. It is merely an accounting term subject to numerous errors including gas theft, variations in temperature and pressure, billing cycle differences, and meter inaccuracies. Used as a surrogate for gas losses, UAG should consistently result in an overestimate of actual emissions to the atmosphere and, for this reason, should not be the basis for emission estimates.

Detailed estimates specific to the U.S. are scarce. An estimate resulting from a study by Pipeline Systems Incorporated was reported by Tilkicioglu [16] to be 3.14 Tg or 0.8% of 1988 production. That study

TABLE 1. ESTIMATES OF GLOBAL METHANE EMISSIONS FROM THE NATURAL GAS INDUSTRY

Source	**Reported Base Year**	**Estimate (Tg/yr)**	**Assumed Loss Rates (%)**
Hitchcock and Wechsler (1972) [4]	1968	7-21	1-3
Keeling (1973) [5]	1968	40-70	6-10
Ehhalt and Schmidt (1978) [6]	1968	7-21	1-3
Sheppard et al. (1982) [7]	1975	50	2 (leakage) + 25% for vented and flared
Blake (1984) [8]	1975	50-60	2-3 (leakage) + 30 Tg for vented and flared
Seiler (1984) [9]	1975	19-29	2-3
Darmstadter et al. (1984) [10]	1980	10	1
Bolle et al. (1986) [11]	Not given	35	3-4
Crutzen (1987) [12]	Not given	33	4
Cicerone and Oremland (1988) [13]	Early 1980s	25-50	2.5 (leakage) + 14 Tg for vented and flared
Barns and Edmonds (1990) [14]	1986	40	0.5 production, 16.2 Tg vented, trans. & dist. is 1.5% of dry production
Fung et al. (1991) [15]	1986	40	Not specified

used existing data and a group of “model” facilities as a basis for extrapolation. A similar approach was adopted by the Environmental Protection Agency’s Office of Air and Radiation in producing their Report to

Congress [17] which estimated industry methane emissions at 2.2 to 4.3 Tg/yr in 1990. While both of these estimates were based on defensible rationale for extrapolation, they both suffer from the paucity of emissions data available when they were produced.

3.0 METHODS

Within this section we will describe the categorization of emission sources used in the study for accounting purposes, the measurement techniques that were employed, how and where these techniques were applied, and the methods of extrapolating these measurements to the larger industry population of sources. Details of all aspects of the study are described in a recently published 15-volume report [18-32] and in a series of reports published by the Gas Research Institute listed in reference 19.

3.1 Source Categorization

In this study all emissions were included from the wellhead to and including the customer meter. In each industry segment, emissions were included only if they resulted from the production of gas for the market. Therefore, in the production sector for example, emissions from equipment whose principal purpose was to produce oil for sale were excluded from the study. However, if one of the byproducts was marketable gas, the equipment used to move the gas to market was included. Similarly, in the gas processing sector, emissions from equipment associated with the fractionation of propane, butane, and natural gas liquids were excluded. Figure 1 shows the boundaries that were drawn around equipment used to produce marketable gas from both gas and oil wells so that the specific equipment that was considered can be visualized. It is important to understand the distinctions that have been made because, in drawing the lines where we have, some high emission rate items of equipment which, by our definitions are associated with oil production, have been excluded. In order to ensure that all emissions from the industry were accounted for, emissions were first defined by the segment of the industry in which the emitting equipment was located, the mode of operation of the equipment when the emissions occurred, and the type of emission.

3.1.1 Industry segments

The production sector includes all subsurface components including the well hole itself along with the associated casing and tubing pipe, as well as the surface equipment including separators, heaters, heater/treaters, tanks, dehydrators, compressors, pumps, and gathering pipelines. Equipment associated with venting, flaring, or reinjecting natural gas from oil wells is not considered part of the gas industry.

Natural gas processing plants recover high value liquids from the gas stream while maintaining the essential content and heating value of the gas stream. Liquid products such as natural gasoline, butane, propane, and in some

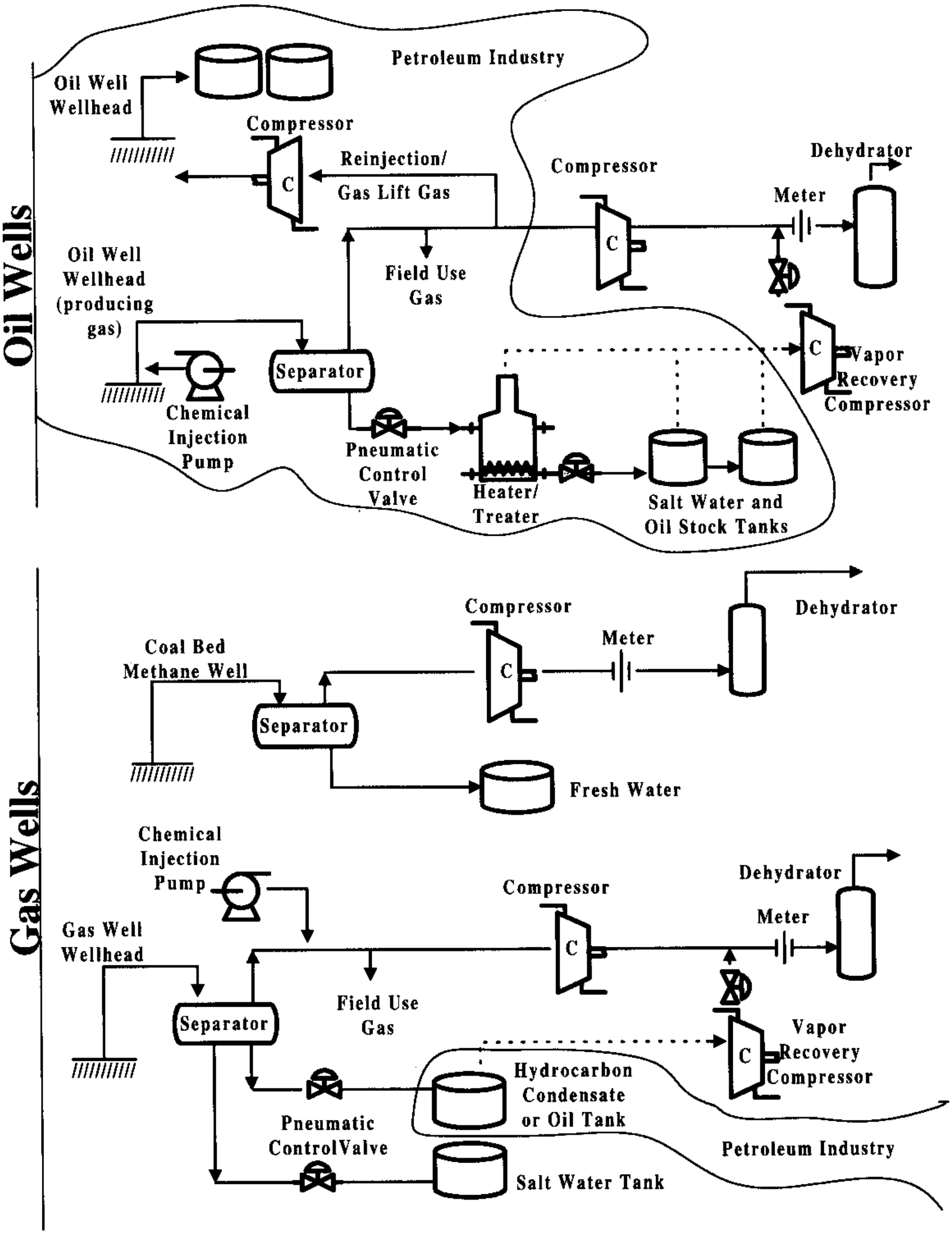
Oil Wells
Petroleum Industry
Oil Well
Wellhead
Compressor
C
Reinjection/
Gas Lift Gas
Compressor
C
Dehydrator
Meter
Oil Well
Wellhead
(producing
gas)
Field Use
Gas
Separator
Vapor
Recovery
Compressor
C
Chemical
Injection
Pump
Pneumatic
Control
Valve
Heater/
Treater
Salt Water and
Oil Stock Tanks
Gas Wells
Compressor
C
Dehydrator
Meter
Coal Bed
Methane Well
Separator
Fresh Water
Chemical
Injection
Pump
Compressor
C
Dehydrator
Meter
Gas Well
Wellhead
Field Use
Gas
Separator
Vapor
Recovery
Compressor
C
Hydrocarbon
Condensate
or Oil Tank
Pneumatic
ControlValve
Petroleum Industry
Salt Water Tank

Figure 1.

cases, ethane, are removed by compression and cooling or by absorption. The back end of the gas plant, such as the fractionation train, is excluded from the gas industry since its function is to purify liquid products for the market. The front end of the gas plant often contains dehydration facilities, wet gas compression, and the absorption or compression and refrigeration processes for upgrading gas for the market and, therefore, is included as part of the gas industry.

The transmission sector moves the natural gas from the gas plants or directly from field production to the local distribution companies. The transmission segment consists of large diameter pipelines, compressor stations, and metering facilities. All of the equipment contained within these facilities is considered to be part of the gas industry. Compressor stations usually consist of piping manifolds, reciprocating engines or gas turbines, reciprocating or centrifugal compressors, and generators. Dehydrators and metering equipment may or may not be present. Transmission companies also have metering and pressure regulating (M&PR) stations where they exchange gas with other transmission companies, or where they deliver gas to local distribution companies or industrial customers. These stations may contain heaters, small dehydrators, and odorant addition equipment.

Above- and below-ground storage facilities exist to store gas produced during off-peak periods for delivery during high-demand periods. They are typically located close to consumption centers so that cross-country transmission pipelines do not have to be sized for peak demand. Above-ground facilities store gas liquefied by supercooling in heavily insulated tanks. Below-ground facilities compress and store vapor-phase gas in spent gas production fields, aquifers, or salt caverns. Most storage stations consist of a compressor station similar to transmission compressor stations. Underground storage facilities also have field wells, and usually have dehydrators to remove moisture absorbed by the gas while underground. All storage facilities and equipment are considered to be wholly within the gas industry.

The distribution segment receives high pressure gas from transmission pipelines, reduces the pressure, and delivers the gas to residential, commercial, and industrial consumers. This segment of the industry includes pipelines for mains and services, M&PR stations, and customer meters. All of these components are part of the gas industry.

3.1.2 Operating modes

After associating each piece of equipment with an industry segment, it was necessary to determine the modes in which this equipment may operate. It is necessary to identify all possible operating modes for each type of equipment because the cause of emissions is directly related to the operating mode at the time. Modes identified were: 1) start-up, 2) normal operation, 3) maintenance, 4) upsets, and 5) mishaps.

Start-up operations, such as purging a newly constructed plant or pipeline, can involve purging natural gas directly to the atmosphere. Emissions associated with normal operation include emissions from process vents, fugitive emissions from packed or sealed surfaces or underground pipeline leaks, and emissions from gas-operated pneumatic devices. Maintenance operations involve blowing down equipment such as compressors, pipelines, or vessels before maintenance begins. Process upsets usually involve releasing gas to the atmosphere or to a combustion device, such as a flare, as the result of overpressure or emergency shutdown conditions. Mishaps include accidental occurrences that result in emissions, such as third-party damage to pipelines commonly known as dig-ins.

3.1.3 Emission types

Emissions from each piece of equipment in the natural gas industry can be classified as one of three general emission types: 1) fugitive emissions; 2) vented emissions; and 3) combustion emissions. Fugitive emissions are unintentional leaks emitted from sealed surfaces, such as packings and gaskets, or leaks from underground pipelines resulting from corrosion or faulty connections. Vented emissions are releases to the atmosphere by design or operational practice. Examples of vented emissions include: emissions from continuous process vents, such as dehydrator reboiler vents; maintenance practices, such as blowdowns; and small individual sources, such as gas-operated pneumatic device vents. Combustion emissions are exhaust emissions from combustion sources such as compressor engines, burners, and flares.

The main purpose for categorizing emissions in this fashion was to determine whether they were steady or unsteady over time and, as a result, whether they could be measured or must be calculated. For emissions that are continuous or relatively steady over long periods of time, a single series of measurements was sufficient to allow annual emissions to be calculated. Since sampling a single source for a year or more to determine annual emissions was not feasible, emissions from sources that are discontinuous or unsteady were calculated using available information, such as volumes of vessels, cross-sectional areas and flow rates of pipes, duration of events, and frequency of events.

3.2 Measurement Techniques for Steady Emissions

Steady emissions result from unintentional leaks from sealed surfaces such as pipe connectors, valve packing, flange gaskets at surface facilities, and components and small holes in underground pipelines. The three methods we used in this study to measure steady emissions--component measurements, tracer gas, and leak statistics-- are described below.

3.2.1 Component measurement methods

One method for determining fugitive emissions from above-ground facilities is to determine emissions from basic components such as valves, flanges, seals, and other connectors and then sum these for a given facility to determine total emissions. As a part of this program a number of studies were conducted to update emission factors for pipe fittings and other components used in oil and gas production [33-38]. Nearly 200,000 components were screened at 33 facilities throughout the country. The approach was to measure emissions from a large number of randomly selected components and to determine the average emission rate or emission factor for each type of component. If a component was leaking, the average emission rate was measured using one of two test methods.

The first approach is based on the EPA Reference Method 21. [39] The EPA protocol involves screening components using a portable instrument to detect total hydrocarbon (THC) leaks. The corresponding screening value for a component, which is a concentration measurement, is then converted to an emission rate by using a correlation equation developed from data collected using an enclosure measurement method. The enclosure method allows the actual leakage rate to be measured as the product of the flow rate of inert gas through the enclosure and the THC concentration. The correlation equation is developed by correlating the screening or concentration data with the emission rate data measured using the enclosure method. The correlation equation can then be applied to the same component type in similar service within the gas industry to estimate emissions using only screening data. The EPA protocol was used to quantify emissions from equipment leaks in onshore production (except for facilities in the Atlantic and Great Lakes regions), offshore production, and gas processing.

The second approach used to quantify component emission factors modifies the EPA protocol approach by using the GRI Hi-Flow™ sampler and direct measurements to replace the data collected using an enclosure approach. The GRI Hi-Flow™ sampler is a newly developed device which allows the leak rate of a component to be measured directly. The sampler creates a flow field around the component in order to capture the entire leak. As the stream passes through the instrument, the flow rate and concentration are measured. The GRI Hi-Flow™ sampling approach was used to quantify emissions from equipment leaks in onshore production in the Atlantic and Great Lakes regions, gas transmission and storage, and customer meters. Direct measurements, such as rotameter readings, were also used on very high leak rates from open-ended lines at transmission and storage compressor stations.

3.2.2 Tracer gas method

The tracer gas method of measuring methane emissions consists of releasing a tracer gas (usually sulfur hexaflouride) at a known constant rate near the emission source and measuring the downwind concentrations of tracer and methane. Assuming complete mixing of the methane and tracer gas and assuming identical dispersion, the ratio of the downwind concentrations of tracer to methane must be equal to the ratio of tracer to methane at the release point. Based upon downwind concentrations of methane and tracer, and the known release rate of the tracer, the emission rate of methane can then be determined. This method was used primarily to measure emissions from M&PR stations [27,40].

3.2.3 Leak statistics method

This method is used to quantify methane emissions from underground main and service pipelines [26]. Emission rates are measured for a large number of leaks to accurately determine the average emission rate per leak as a function of pipe material, age, operating pressure, and soil characteristics. The measurement program was a cooperative effort with industry, in which the industry used a standard sampling protocol and specially designed test equipment to measure leaks from mains and services. In the procedure, a pipe segment containing the leak is isolated, the isolated segment repressurized, and the volumetric flow required to maintain normal operating pressure in the isolated segment is equal to the leak rate. Historical leak records are analyzed to determine the number of leaks per mile for different pipe materials. Total emissions are determined by multiplying the average leak rate per leak by the estimated total number of leaks in the distribution segment.

3.3 Calculation of Unsteady Emissions

For some methane emission sources, such as releases during maintenance, detailed company records were available for multiple years, and a reasonable calculation of average annual emissions could be made. However, many other sources of unsteady emissions are not tracked by companies and, therefore, must be calculated.

Each unsteady source of emissions requires data gathering and a unique set of equations to quantify the average annual emissions. In general, all unsteady sources of emissions require the following information to quantify annual emissions: 1) detailed technical characterizations of the sources and identification of the important parameters affecting emissions; 2) data from multiple sites that allow the methane emitted per emission event to be calculated from the governing equations; and 3) data on the frequency of releases.

The estimate of emissions from a vessel blowdown for routine maintenance is an example of emissions calculated for an unsteady source. In this case the volume, pressure, and temperature of gas contained in the vessel before blowdown is used to calculate losses from a blowdown event. Additionally, an average frequency of these vessel blowdown events is necessary to determine the annual loss.

In some cases, emissions per event from some unsteady sources were measured. These emissions data were combined with site data collected in this study to quantify the annual emissions from these sources. Examples of sources where emission measurements per event were used include emissions from compressor driver exhaust, gas-operated pneumatic devices, glycol dehydrator regenerator overhead vents, and gas-operated chemical injection pumps.

3.4 Sampling and Extrapolation

Because of a number of practical limitations, neither random sampling nor stratified random sampling was feasible in this study. The approach which seemed most appropriate was similar to disproportionate stratified random sampling but with certain differences. Initially, data were collected to determine if a given source was a major contributor to methane emissions. For each source category, an initial estimate of the number of data points needed was calculated based on an estimate of the target precision and the estimated standard deviation for the source category. Accuracy targets for precision are based on the need to estimate the 1992 national emissions to within 0.5%

of U.S. natural gas production with a 90% confidence limit. Sites were selected in a random fashion from available lists of facilities, such as Gas Research Institute or American Gas Association member companies. However, the companies contacted were not required to participate, and a complete listing of all sources in the U.S. was generally not available. Therefore, the final set of companies selected for sampling was not truly random.

After a limited set of data was collected, the data were screened for bias by evaluating the relationship between emission rate and parameters that may affect emissions. If we identified a parameter or set of strata that had a large affect on emissions from a given source, we then determined if the sampling procedure had produced a disproportionate number of samples in those strata. To determine whether this had occurred, we compared the ratio of the total number of sources in a given stratum to the total number of sources throughout the country. If this ratio is different from the corresponding ratio for the sample data set, then bias may have been introduced. We then eliminated the bias by applying the correct emission factors and activity factors for the different strata.

Once we had identified the important strata, the precision of the emission rate extrapolated to a national basis was calculated and compared to the accuracy target. Where necessary, we collected additional data in various strata to improve the precision of the estimate of emissions from the source. The number of additional data points needed to meet the newly calculated accuracy target was computed based on the standard deviation and a 90% confidence interval. Most source activity and emission factors are made up of an average of multiple measurements or calculations. Therefore, assuming a normal distribution around a mean and error independence, standard deviations and 90% confidence limits were calculated directly for each group of measurements in an activity or emission factor. The confidence intervals or error bounds were propagated through the addition of multiple emission source estimates to arrive at a confidence bound for the national emission estimate. These generally accepted statistical techniques are described in detail in a statistical methods report [21].

The sampling procedure described above was one of the methods we employed in an attempt to minimize bias in the data. The absence of bias cannot be proven; however, one can use a number of methods to screen for bias and then eliminate it when it is found. In addition to our sampling precautions, we also screened data for bias by evaluating the relationship between the emission rates and parameters that may affect emissions. The data set was first stratified by the parameter(s) found to significantly influence emissions. Because the sample set collected was not necessarily representative of the nationwide proportions of sites in each stratum, an emission factor per stratum was produced along with an activity factor per stratum to eliminate bias in the disproportionate data set.

Other techniques employed to minimize bias included evaluating regional differences in operating practices or gas composition. In many cases, regional differences were found and the data were stratified by region in order to account for these differences in the emissions estimation procedure. A group of industry experts was also used to review the data and approach for estimating emissions, so that any additional biases could be identified and eliminated. Experts from each industry sector as well as other reviewers were called upon to regularly review the project sampling approach, extrapolation techniques, and preliminary estimates. These reviewers identified biases that were then eliminated through changes to techniques or through additional data collection. We believe that with this combination of techniques all significant sources of bias have been identified and removed.

Once the data were in an acceptable form, these estimates of emissions from a limited number of sources had to be extrapolated to the national level. At that point it became a simple matter of multiplying the emission factor by the activity factor to obtain a national estimate. Typically the emission factor for a source represents the average emissions rate per source, and the activity factor represents the total industry population of the source category.

4.0 RESULTS AND DISCUSSION

In this section we present a summary of annual methane emissions by emission type: fugitive, vented, and combusted. We also provide a brief description of how the estimates were made and the kinds of measurements that were used. At the end of the section we rearrange the results by industry segment which may be more useful to some readers.

Table 2 sets out our estimates of methane emissions from the largest sources within the U.S. gas industry arranged by emission type. Figure 2 further subdivides the category of fugitive emissions so that the contribution from compressors alone can be identified. This subdivision could be useful should the decision be made to attempt to reduce gas losses from portions of the industry.

4.1 Fugitive Emissions--Equipment Leaks

Fugitive emissions from equipment leaks in the natural gas industry were estimated to be 146.9 Bscf (4160.2 x 10^6 m^3). The breakdown of these emissions among various types of facilities is shown in Table 2. From the subdivision shown in Figure 2 it can be seen that 82.1 Bscf (2325.1 x 10^6 m^3) come from the compressors within these facilities, while other facility emissions amount to only 27.2 Bscf (770.3 x 10^6 m^3).
These high compressor emissions can generally be attributed to their unique design, size, and operation, as well as from the vibrational wear associated with the units.

TABLE 2. METHANE EMISSIONS FROM THE LARGEST SOURCES IN THE U.S. NATURAL GAS INDUSTRY

Source		Annual Methane Emissions (Bscf)	Annual Methane Emissions ($10^6 m^3$)	% of Total
Fugitive Emissions	**Subtotal**	**195.3**	**5530.9**	**62.1**
Equipment Leaks				
Compressor Stations (transmission and storage)[a]		67.5	1911.6	21.5
Production Facilities		17.4	492.8	5.5
Gas Plants		24.4	691.0	7.8
Metering and Pressure Regulating Stations[b]		31.8	900.6	10.1
Customer Meter Sets		5.8	164.3	1.8
Underground Pipeline Leaks (all segments)		48.4	1370.7	15.4
Vented Emissions	**Subtotal**	**94.2**	**2667.7**	**30.0**
Pneumatics		45.7	1294.2	14.6
Blow and Purge		30.2	855.3	9.6
Dehydrator Glycol Pumps		11.1	314.4	3.5
Dehydrator Vents		4.8	135.9	1.5
Chemical Injection Pumps		1.5	42.5	0.5
Other		0.9	25.5	0.3
Combusted Emissions	**Subtotal**	**24.9**	**705.2**	**7.9**
Compressor Exhaust		24.9	705.2	7.9
	Total	**314**	**8892.5**	**100**

[a]Includes wells at storage facilities

[b]Emissions from meter and pressure regulating stations result from both pneumatic and fugitive emissions. Since these components cannot be separated using the tracer measurement method, emissions are shown as fugitive by default.

Fugitive emissions are generally measured by either the tracer method or the component method. The tracer method was described briefly above and is described in more detail in reference 27. It has been used to measure emissions from metering and pressure regulating stations. The component approach was used to estimate fugitive emissions from gas production facilities, processing plants, transmission/storage facilities, and customer meters. [33,35,36,38] Separate component emission factors were developed for each industry segment because of differences in design and operating practices that could lead to differences in emissions characteristics. Some regional differences were also determined to have an impact on fugitive emissions so, for example, separate factors were developed for onshore and offshore production facilities.

For gas processing, transmission, and storage, separate emission factors were developed for components physically connected to, or directly adjacent to, compressors because of their significantly higher emission rates. Emissions for an industry segment were then calculated as the sum of compressor-related components and station components. The following subsections explain how fugitive emissions were calculated for each of the facility types that were significant contributors to total national emissions.

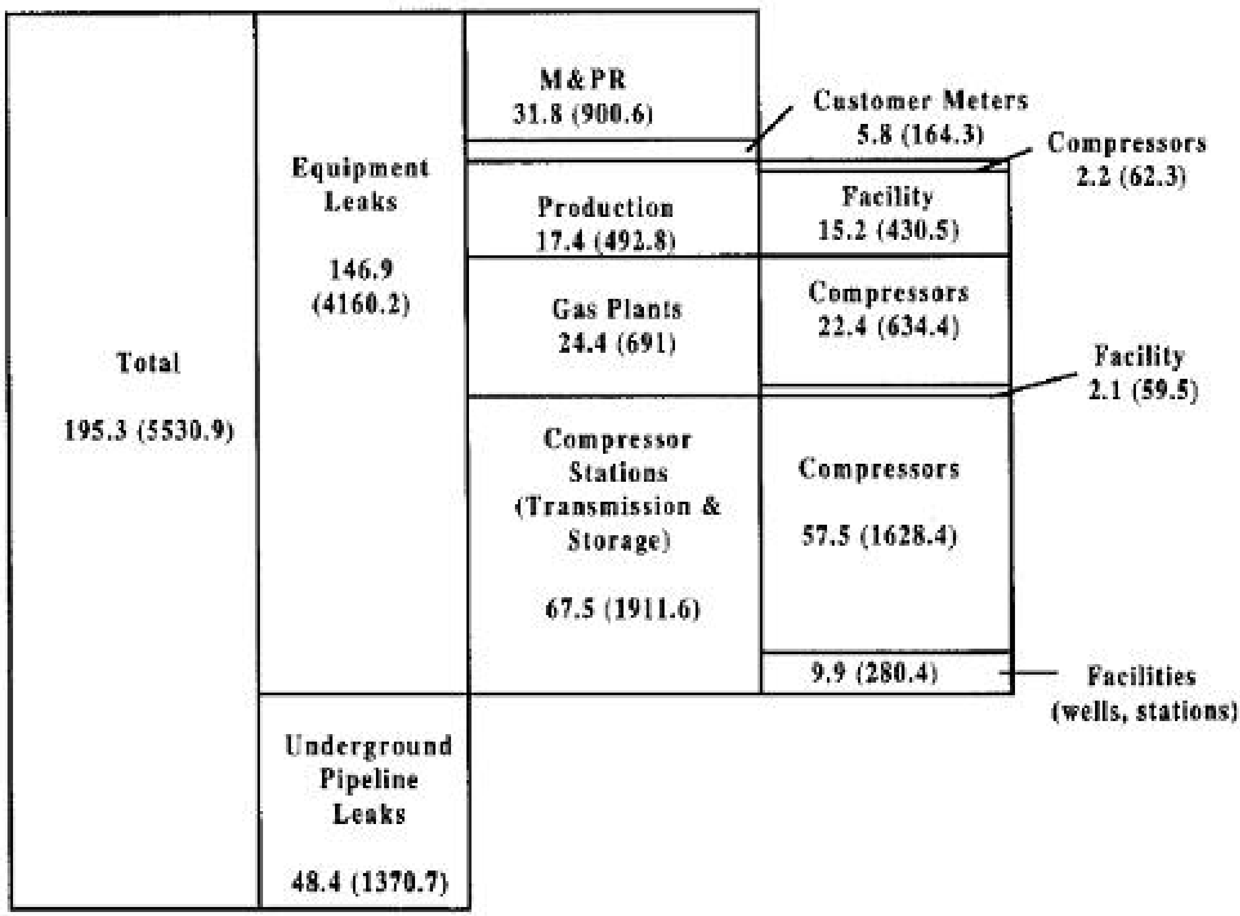

Figure 2. Major Contributors to Fugitive Emissions-- By Segment Facilities in Bscf (and $10^6 m^3$). Not all column totals will match subcolumn totals due to method of rounding significant figures.

4.1.1 Compressor stations--transmission and storage

Compressor stations in transmission and storage are one of the largest sources of fugitive emissions. Equipment leaks from transmission compressor stations were separated into two distinct categories because of differences in leakage characteristics: 1) station components including all sources associated with the station inlet and outlet pipelines, meter runs, dehydrators, and other piping located outside of the compressor building; and 2) compressor-related components including all sources physically connected or immediately adjacent to the compressors. The types of components associated with compressors include compressor blowdown open-ended lines, starter open-ended lines, compressor seals, pressure relief valves, cylinder valve covers, and fuel valves. Fugitive emissions from compressor stations are dominated by emissions from components related to compressors, which emit 57.5 Bscf (1628.4 x 10^6 m^3), while emissions from all of the remaining components not associated with compressors contribute only 9.9 Bscf (280.4 x 10^6 m^3).

Fugitive emissions were estimated from measurement data collected at 15 compressor stations using the GRI Hi-Flow™ sampler. [36] Based on the measurement data, fugitive emissions from the compressor blowdown open-ended line were found to be the largest source. Compressor blowdown open-ended lines allow a compressor to be depressurized when idle, and typically leak when the compressor is operating or idle. Two primary modes of operation lead to different emission rates for these open-ended lines: 1) the blowdown valve is closed and the compressor is pressurized, either during normal operation or when idle; or 2) the valve is open when the compressor is idle, isolated from the compressor suction and discharge manifolds, and the blowdown valve is opened to depressurize the compressor. The fugitive emission rate is higher for the second operating mode when the blowdown valve is open, since leakage occurs from the valve seats of the much larger suction and discharge valves. Separate component emission factors were developed for the two operating modes of the compressor blowdown open-ended line. An overall average component emission factor was derived for compressor blowdown open-ended lines by determining the fraction of time transmission compressors operate in each mode (i.e., pressurized or depressurized).

The majority of compressor fugitive emissions result from the transmission and storage segments, where a large number of very large compressors exist. Since compressors are also a part of production facilities and gas plants, the compressor component emission factors developed for the transmission and storage segments were also used for compressor components in those segments.

4.1.2 Production facilities

Annual fugitive emissions from gas production facilities in the U.S. were estimated to be 17.4 Bscf (492.8 x 10^6 $m^{3)}$. Component emission factors for fugitive equipment leaks in gas production were estimated separately for onshore and offshore production due to differences in operational characteristics. Regional differences were found to exist between onshore production in the Atlantic and Great Lakes regions (Eastern U.S.) and the rest of the country

(Western U.S.), and between offshore production in the Gulf of Mexico and the Pacific Outer Continental Shelf. In general, these regional differences were due to differences in the number, type, age, and leak detection and repair characteristics of equipment. Therefore, separate measurement programs were conducted to account for these regional differences.

For onshore production in the Eastern U.S., component emission factors and average component counts were based on a measurement program using the GRI Hi-Flow™ sampler to quantify emission rates from leaking components. [34] A total of 192 individual well sites were screened at 12 eastern gas production facilities. Fugitive emissions from onshore production in the rest of the U.S. were estimated using the EPA protocol. Component emission factors were based on screening and enclosure data collected from 83 gas wells at 4 gas production sites in the Western U.S. [37] The average component counts were based on data from the onshore production measurement program and additional data collected during 13 site visits to gas production fields. [25]

Emissions from equipment leaks at offshore production sites in the U.S. were quantified based on two separate screening and enclosure studies using the EPA protocol: 1) the oil and natural gas production operations measurement program, [37] which included four offshore production sites in the Gulf of Mexico; and 2) the offshore production measurement program, [41] which included seven offshore production sites in the Pacific Outer Continental Shelf.

4.1.3 Gas processing plants

Fugitive emissions from gas processing plants contribute 24.4 Bscf (691.0 x 10^6 m^3) to national annual methane emissions. The majority of fugitive emissions from gas processing plants are attributed to compressor-related components, which account for 22.4 Bscf (634.4 x 10^6 m^3). The component emission factors for compressor-related components in gas processing plants were based on the fugitives measurement program at 15 compressor stations. [25] Fugitive emissions from the remaining gas plant components, not associated with compressors, were estimated based on the oil and gas production measurement program. [33] In the oil and gas production measurement program, equipment leaks from a total of eight gas processing plants were measured using the EPA protocol.

4.1.4 Meter and pressure regulating stations

Fugitive emissions from meter and pressure regulating stations (M&PR stations) contribute 31.8 Bscf (900.6 x 10^6 m^3) to total annual methane emissions. Emissions from this category of surface equipment were measured using the tracer measurement approach and, therefore, were reported separately from other categories of surface equipment fugitives. A total of 95 M&PR facilities were measured using the tracer technique. [27]

The primary losses from M&PR stations include both fugitive emissions and, in some cases, emissions from pneumatic devices. Since the tracer measurement technique used does not differentiate between fugitive and vented emissions, the vented pneumatic emissions are, therefore, included in the fugitive category by default. Some pressure regulating stations use gas-operated pneumatic devices to position the pressure regulators. These gas-operated pneumatic devices bleed to the atmosphere continuously and/or when the regulator is activated for some system designs. Other designs bleed the gas downstream into the lower pressure pipeline and, therefore, have no losses associated with the pneumatic devices.

Tracer measurements were used to derive the emission factors for estimating emissions from M&PR stations in both the transmission and distribution segments of the gas industry. The total emissions are a product of the emission factor and activity factor, which were stratified into inlet pressure and location (above ground versus in vaults) categories to improve the precision of the emission estimate.

M&PR stations in the distribution segment include both transmission-to-distribution custody transfer points and the downstream pressure reduction stations. The emission factors for distributions are based on the average measured emissions for each station category, and the activity factors are based on the average data supplied by 12 distribution companies. The annual methane emissions for the M&PR stations in the distribution segment of the industry are 27.3 Bscf (773.1 x 10^6 m^3).

For the transmission segment, the stations include transmission-to-transmission custody transfer points and transmission-to-customer transfer. Emission factors for the transmission segment are derived from the tracer measurement database for M&PR stations, and the activity factors are based on survey data from six transmission companies. The annual estimated methane emissions for the transmission segment are 4.5 Bscf (127.4 x $10^6 m^3$).

4.1.5 Customer meter sets

Fugitive emissions from commercial/industrial and residential customer meter sets contribute 5.8 Bscf (164.3 x $10^6 m^3$) total national emissions. The average leak rate per residential meter set is only 0.01 scf/hr (0.0003 m^3/hr), but there are approximately 40 million customer meters located outdoors. The meter sets include the meter itself and the related pipe and fittings. Methane emissions from commercial and residential customer meter sets are caused by fugitive losses from the connections and other fittings surrounding the meter set. No losses have been found from the meter itself.

Methane emissions from customer meter sets were estimated based on fugitives screening data collected from 10 cities across the U.S. [25,35,38] Although a total of around 1600 meter sets were screened as part of this study, only about 20% of the meter sets screened were found to be leaking at low levels. For the majority of customer meter sets screened, the GRI Hi-Flow™ device was used to develop emission factors. For the other meter sets screened, the EPA protocol was used to convert the screening data into emission rates.

Emission factors for residential customer meter sets were defined as the average methane leakage rate per meter set for outdoor meters. Emissions from indoor meters are much lower than for outdoor meters because gas leaks within the confined space of a residence are readily identified and repaired. This is consistent with the findings that pressure regulating stations located in vaults have substantially lower emissions than stations located above ground. Emission factors for commercial/industrial meter sets were estimated separately as the average emission rate per meter set.

The activity factors for residential customer meter sets were defined as the number of outdoor customer meters in the U.S. The activity factor was based on published statistics including a breakdown of residential customer meters by region in order to estimate the number of meter sets located indoors. Data were obtained from 22 individual gas companies within different regions of the U.S. to estimate the number of residential customer meters.

4.2 Fugitive Emissions--Underground Pipeline Leaks

Fugitive leakage from underground piping systems contributes 48.4 Bscf (1370.7 x 10^6 m^3) to total methane emissions. Pipeline leaks are caused by corrosion, material defects, and joint and fitting defects/failures. Based on limited leak measurement data from two distribution companies, leakage from underground distribution mains and services was targeted as a potentially large source of methane emissions from the gas industry.

A leak measurement technique was developed to quantify methane emissions from underground pipelines in the natural gas industry. [26] A total of 146 leak measurements were collected from the participating companies. These data were used to derive the emission factors for estimating methane leakage from distribution, transmission, and production underground pipelines. The total emissions are a product of the emission factor and activity factor, and are stratified by pipe use (mains versus services) and pipe material categories to improve the precision of the estimate.

The soil oxidation rates of methane were experimentally determined to be a function of the methane emission rate, pipe depth, and soil temperature. [42] The methane leakage rate for underground pipelines was determined to be a function of the pipe service (mains versus services) and the pipe material type. In general, the larger the leakage rate per leak, the lower the soil oxidation rate. Because of the types of pipelines in service in the distribution segment, the overall leakage rate per peak is lower. Therefore, the overall oxidation rate for distribution pipelines is higher than for transmission or gathering lines.

In the distribution segment, activity factors were based on the national database of leak repairs broken down by pipe material using information from 10 companies, and then combined with historical leak records provided by 6 companies. The activity factors represent the number of equivalent leaks that are continuously leaking year round; repaired leaks are counted as fractional leaks. The activity factor combined with the factors derived from the leak measurement data produced an overall methane emissions estimate of 41.6 Bscf (1178.1 x 10^6 m^3) which includes an adjustment for soil oxidation. The largest contributor to the overall annual emissions was cast iron mains, followed by unprotected steel services and mains. The average soil oxidation rate applicable to distribution piping was 18%, which primarily affects the emissions from cast iron mains which have low leak rates per leak.

In the transmission and production segments, the estimated methane leakage was based on the emission factors derived from the leak rates measured on distribution mains and on activity factors derived from a nationally tracked database of pipe mileage/leak repairs. [43] For transmission pipeline leakage, the estimated annual methane emissions were 0.2 Bscf (5.7 x 10^6 m^3) which includes an adjustment for soil oxidation. For gathering pipeline in the production segment, the estimated annual methane emissions were 6.6 Bscf (186.9 x 10^6 m^3). The estimated methane emissions to the atmosphere from gathering lines include an adjustment of 5% average methane oxidation in the soil.

4.3 Vented Emissions

Vented emissions primarily result from three categories: 1) pneumatic devices; 2) blow and purge emissions, and 3) dehydrator emissions. Emissions from chemical injection pumps and other sources are minor.

4.3.1 Pneumatic devices

Pneumatic devices in the natural gas industry are valve actuators and controllers that use natural gas pressure as the force for valve movement. Gas from the valve actuator is vented during every valve stroke, and gas may bleed continuously from the valve controller pilot as well. Pneumatic devices are a major source of unsteady emissions and account for 45.7 Bscf (1294.2 x 10^6 m^3) of methane emissions. [29] Methane emissions from pneumatic devices were calculated based on field measurements, site data, and manufacturers' data.

There are two primary types of these devices: 1) control valves that regulate flow, and 2) isolation valves that block or isolate equipment and pipelines. Of the two main types, isolation valves typically have lower annual emission rates, although the emission rate per actuation can be high. This is because isolation valves are moved infrequently for emergency or maintenance activities that require isolating a piece of equipment or section of pipeline. Alternatively, control valves typically move frequently to make adjustments for changes in process conditions, and some types of control valves bleed gas continuously.

Emission factor estimates for pneumatic devices were based on a combination of site information, manufacturers' data, and measured emissions from devices in the field. Each segment of the industry has very different practices regarding the use of pneumatic devices. These differences and a summary of the data collected to characterize the different pneumatic devices are described below.

The production segment accounts for the majority of the pneumatic emissions: 31.4 Bscf (889.2 x $10^6 m^3$) or 69% of all pneumatic emissions. High pressure natural gas is used to operate most of these devices, since production facilities are usually located at remote sites and natural gas is readily available and less expensive than compressed air or electricity. The majority of devices are used to regulate flow and can emit methane either on a continuous basis or only when the device is actuated. Data were collected from 22 sites to determine the fraction of continuous bleed devices versus intermittent bleed devices. A total of 44 measurements of various device types in field operation were used to estimate the emission factor. In addition, the four most common manufacturers of these devices were contacted for information regarding the characteristics of the devices that affect emissions. The total number of pneumatic devices in the production segment were determined based on data from more than 35 sites.

Pneumatic device emissions from the gas processing segment are very small: 0.1 Bscf (2.8 x 10^6 m^3) or less than 1% of all pneumatic emissions. Emissions were based on data collected from nine gas processing plants and from the four manufacturers of the devices observed. Of the gas processing plants surveyed, only about half (56%) use natural gas to operate pneumatic controllers and isolation valves; other sites use compressed air or electric motors. The natural gas powered isolation valves in this industry segment are operated only once per month or once per year, so the emissions per site are relatively small.

Emissions from pneumatic devices at transmission compression stations and storage stations account for 14.1 Bscf (399.3 x $10^6 m^3$) or 31% of pneumatic emissions. In this industry segment, most of the pneumatics are gas-actuated isolation valves. Data for these types of devices were provided by 16 sites and 2 manufacturers. There are a few pneumatic control valves used to reduce pressure or to control liquid flow from a separator or scrubber. Emissions for these devices were based on information collected from 54 sites and 23 measurements of operating devices. Site data from 54 stations were also used to determine the number of devices per station, which was extrapolated to a national number of pneumatic devices in the transmission segment.

Pneumatic emissions for the distribution segment are included in the "fugitive" emission factor for M&PR stations. The M&PR pneumatics cannot be separated from fugitives, since M&PR total emissions were measured using the downwind tracer technique.

4.3.2 Blow and purge

Blow and purge is a major source of unsteady emissions and accounts for approximately 30.2 Bscf (855.3 x 10^6 m^3) of methane emissions. [24] Blow (or blowdown) gas refers to intentional and unintentional venting of gas for maintenance, routine operations, or emergency conditions. A piece of process equipment or an entire site is isolated from other gas containing equipment and depressurized to the atmosphere. The gas is discharged to the atmosphere for one of two reasons: 1) maintenance blowdown-- the gas is vented from equipment to eliminate the flammable material inside the equipment providing a safer working environment for personnel that service or enter the equipment; or 2) emergency blowdown-- the gas is vented from a site to eliminate a potential fuel source, for example in case of fire. The factors that affect the volume of methane blowdown released to the atmosphere are frequency, volume of gas blowdown per event, and the disposition of the blowdown gas.

Blowdown from maintenance releases were determined by equipment category: compressor blowdown, compressor starts, pipeline blowdown, vessel blowdown, gas wellbore blowdown, and miscellaneous equipment blowdowns. Emergency blowdowns refer to the unexpected release of gas by a safety device, such as a pressure relief valve (PRV), on a vessel or the automatic shutdown/emergency blowdown of a transmission compressor station. Dig-ins, pipeline ruptures caused by unintentional damage, were also classified under emergency release of gas and included in the blow and purge estimates.

Emission estimates for each industry segment were based on data from site visits or company tracked data. Blow and purge emissions from the production segment, accounting for approximately 6.5 Bscf (184.1 x 10^6 m^3) of the total blow and purge emissions, were based on data from 25 sites. Emissions for transmission and gas processing plants, which have similar station blowdown practices, were based on data from eight companies. These industry segments account for 18.5 Bscf (523.9 x 10^6 m^3) and 2.9 Bscf (82.1 x 10^6 m^3) of the total blow and purge emissions, respectively. The distribution segment makes up about 2.2 Bscf (62.3 x 10^6 m^3) of the total blow and purge emissions, and the emission estimate for this segment was based on detailed lost-gas studies from two distribution companies. [44,45]

4.3.3 Glycol dehydrator pumps

Glycol dehydrator circulation pumps are a major source of unsteady emissions and account for 11.1 Bscf (314.4 x 10^6 m^3) of methane emissions. [32] These pumps use the high pressure of the rich glycol from the absorber to power pistons that pump the low pressure, lean glycol from the regenerator. The pump configuration pulls additional gas from the absorber along with the rich glycol, more gas than would flow with the rich glycol if conventional electrical pumps and level control were used. This gas is emitted through the dehydrator vent stack along with the methane absorbed in the rich glycol stream.

Gas-powered glycol circulation pumps are common throughout the industry even at sites where electrical pumps are the standard for other equipment. The dehydrator equipment is often specified as a separate bid package, and the vendors most often use the Kimray gas pump as their standard pumping unit. The pumps are an integral part of the glycol dehydrator unit, and their emissions occur through the same point. However, the pumps are the cause for nearly half of the methane emissions from dehydrators, so they are considered separately.

Unlike chemical injection pumps, which vent the driving gas directly to the atmosphere, dehydrator pumps pass the driving gas along with the rich (wet) glycol to the reboiler. Therefore, methane emissions from the pump depend on the design of the dehydrator since gas recovery on the dehydrator will also recover gas from the pump. The demographics generated for the glycol dehydrator control system (flash drum recovery and vent vapor recovery) were also used to determine the net emission rate for glycol pumps. Design data from Kimray were used to establish the amount of gas used by these pumps. Gas-assisted glycol pumps were found almost exclusively in production dehydrators, with a few in gas processing. No active gas-assisted pumps were found during the site visits to transmission or storage facilities which is consistent with the fact that larger facilities tend to use electricity.

4.3.4 Dehydrator vents

Glycol dehydrator vents are a major source of methane emissions and account for 4.8 Bscf (135.9 x $10^6 m^3$) of methane emissions. [32] The majority of the glycol dehydrators are located in production, but dehydrators are also used in gas processing, transmission, and storage. Methane emissions are highest in the production segment; 71% of the total dehydrator vent emissions are attributed to dehydrators in the production segment. This is due to the high activity and emission factors for this segment. The absence of flash tanks in most production dehydrators leads to an emission rate per volume of gas dehydrated that is higher in production than in the other segments.

Glycol dehydrators remove water from the natural gas through continuous glycol absorption. The water-rich glycol is regenerated, or heated, which drives the water back out of the glycol. The glycol also absorbs some other compounds from the gas, including a small amount of methane. The methane is driven off with the water in the regenerator and vented to the atmosphere.

The important emission-affecting variables for dehydrators are: gas throughput, use of a flash tank, use of stripping gas, and use of vent controls where the gas is routed to a burner. An emission factor per unit of gas throughput was established for glycol dehydrator regenerator vents using three sources of data: 1) computer simulations of dehydrator operations using first principles; 2) data from actual samples taken from regenerator vents; and 3) multiple site visits. The emission factor was combined with an activity factor to generate the emission rate. The activity factors are the volumes of gas dehydrated in each industry segment. The total glycol dehydrator throughput compares well with a separate study conducted by API. [46]

4.3.5 Chemical injection pumps

Chemical injection pumps are a small source of unsteady emissions and account for 1.5 Bscf (42.5 x 10^6 m^3) of methane emissions solely in the production segment. [30] Emission estimates for this source were based on data from 17 sites, 6 manufacturers, and emission measurements from a Canadian study. [47] The total number of chemical injection pumps nationally was extrapolated from data relating the number of chemical injection pumps to the number of gas wells at 38 sites.

Gas-driven chemical injection pumps use gas pressure to move a piston which pumps the chemical on the opposite end of the piston shaft; the power gas is then vented to the atmosphere at the end of the stroke. The power gas may be natural gas or compressed air. Two types of chemical injection pumps were observed: 1) piston pumps and 2) diaphragm pumps. The larger diaphragm pumps emit more gas per stroke, and they are used to pump a higher flow rate of chemical or to pump the chemical into high pressure equipment.

Chemical injection pumps are used to add chemicals such as corrosion inhibitors, scale inhibitors, biocides, demulsifiers, clarifiers, and hydrate inhibitors to operating equipment. These additives protect the equipment or help maintain the flow of gas. The vast majority of these pumps exist in the production segment where the gas is wet and has a high non-methane content. The pumps are most often located at the well sites, so that the chemical can protect all of the downstream and downhole equipment. Most of the chemical injection pumps in oil and gas production are associated with oil production and were not included in this study. As with pneumatic control valves, the chemical injection pumps in production are primarily powered by natural gas.[30]

In the production segment, significant regional differences exist. Depending on the gas composition and conditions, some regions use very few pumps, while other regions use the pumps frequently. Many pumps also have seasonal operation since they protect against hydrate formation which winter temperatures exacerbate. Only a few pumps exist in the gas processing and transmission segments. The pumps that do exist are powered by compressed air at these stations and, as a result, have no methane emissions.

4.4 Combusted Emissions

Combusted emissions result from incomplete combustion of methane in burners, flares, and engines. Incomplete combustion of methane in compressor engine exhaust is the only significant source of methane in this category.

Methane emitted to the atmosphere in compressor driver exhaust is a major source of unsteady emissions and accounts for 24.9 Bscf (705.2 x 10^6 m^3) of methane emissions. [28] Methane emissions result from the incomplete combustion of the natural gas fuel, which allows some of the methane in the fuel to exit in the exhaust stream. There are two primary types of compressor drivers: 1) reciprocating gas engines, and 2) gas turbines. A few compressors in the industry are driven by other means such as electric motors, but the majority are natural gas fueled. In addition to compressors, there are some natural gas drivers that run electrical generators at gas plants and compressor stations.

Reciprocating engines emit approximately 40 times more methane per horsepower or per unit of fuel consumed than gas turbines. Reciprocating engines account for over two-thirds of all installed horsepower in the gas industry. Therefore, reciprocating engine compressor drivers account for over 98% of the methane emissions for this category.

Emissions were determined by analyzing and combining several databases to generate emission factors and activity factors. A GRI database, the TRANSDAT compressor module, [48] contains data from AGA (American Gas Association) on types and models of compressors in use, as well as data on compressor driver exhaust from the Southwest Research Institute (SwRI). AGA gathers its data from government agencies, such as the U.S. Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC), and from surveys of its member companies in transmission and distribution. SwRI data were generated through actual field testing. These data were combined to generate emission factors for this project by correlating compressor driver type, methane emissions, fuel use rate, and annual operating hours for 775 reciprocating engines and 86 gas turbines.

Horsepower•hour activity factors were developed for each industry segment using data from GRI TRANSDAT, FERC, AGA, company databases, and site visits. GRI TRANSDAT includes horsepower data for

7489 reciprocating engines and 793 gas turbines in transmission. Transmission operating hours were based on FERC data for 1992 and one company's data for 524 reciprocating engines and 89 gas turbines. Storage horsepower and operating hours were based on AGA data and data from 11 storage stations, respectively. Since national totals for transmission and storage horsepower were available, no industry extrapolation was necessary for these activity factors. Production horsepower•hours were based on one company's data for 513 reciprocating engines and 6 gas turbines. Processing horsepower and operating hours were based on 10 site visits and company data for 11 gas processing plants. Activity factors for production and processing were extrapolated to the industry using published data for nationally marketed gas production and gas processing, respectively.

4.5 Largest Sources by Industry Segment

Companies within each industry segment will undoubtedly be interested in their own emissions and their sources, as will policy makers. In this section we have recast the data so that emissions from each industry segment and the largest categories within each segment can be seen. Table 3 summarizes emissions by industry segment, and Table 4 breaks these emissions down further by type. As shown earlier, fugitive emissions are the largest emission type for the industry as a whole. It can be seen in Table 4 that they are also the largest emission type for each industry segment except production where vented emissions prevail. Vented emissions are high in the production sector because of the contribution from pneumatic devices. The transmission/storage sector has the highest emissions of 116.5 Bscf (3299.3 x 10^6 m^3), largely because of fugitive emissions associated with compressor stations. The production and distribution sectors have more or less equal emission levels of 84.4 and 77.0 Bscf (2390.2 and 2180.6 x 10^6 m^3), respectively. Emissions in the production sector are driven by vented gas from pneumatic devices and fugitive emissions. Distribution sector emissions are driven primarily by underground pipeline leaks and M&PR stations. The processing sector has the lowest emissions of 36.4 Bscf (1030.8 x 10^6 m^3) produced largely by fugitives and to a lesser extent by compressor driver exhaust.

It should be noted in both Tables 3 and 4 that the error estimates for the totals cannot be directly derived from the error estimates of the table entries for two reasons: first, errors were propagated by a sum of squares technique using a level of data not presented in this paper; second, error estimates for cell entries are based on a 90% confidence interval assuming a normal distribution, while error estimates for the total are based on the upper limit of a 90% confidence interval, allowing for a reasonable asymmetry in the error distribution and statistical dependence in the errors for some sets of source categories. This conservative approach was adopted to avoid, as far as possible, overstating confidence in the final industry estimates.

5.0 CONCLUSIONS

In a Report to Congress the U.S. Environmental Protection Agency has estimated the contribution of methane from all U.S. anthropogenic sources, excluding the natural gas industry, to be 1190 to 1336 Bscf (33,700.8 to 37,835.5 x 10^6 m^3). [17] Therefore the 314 Bscf (8892.5 x 10^6 m^3) of methane emissions estimated from the U.S. gas industry in this study accounts for 19 to 21 % of U.S. anthropogenic methane emissions. This compares to emission estimates for other significant sources of 31 % from landfills, 19 % from domestic livestock, 15 % from coal mines, 9 % from livestock manure, and 6 % from other sources.

TABLE 3. SUMMARY OF METHANE EMISSIONS

Segment	Emissions, Bscf ($10^9 m^3$)	Percent of Total Emissions (%)	Emissions as a Percent of Gross National Production (1992)[a]
Production	84.4 ± 37.0[b] (2.39 ± 1.05)	26.8 ± 11.8	0.38 ± 0.17
Processing	36.4 ± 20.6 (1.03 ± 0.58)	11.6 ± 6.6	0.16 ± 0.09
Transmission/Storage	116.5 ± 58.0 (3.30 ± 1.64)	37.1 ± 18.5	0.53 ± 0.26
Distribution	77.0 ±53.6 (2.18 ± 1.52)	24.5 ± 17.1	0.35 ± 0.24
Total	**314 ± 105**[c] **(8.89 ± 2.97)**	**100.0 ± 33.4**	**1.42 ± 0.47**

[a] 1992 Gross national production = 22,132 Bscf (626.8 x 10^9 m^3). [49]
[b] Precision is based on a 90% confidence interval, assuming a normal distribution.
[c] Total precision is based on a 90% confidence interval, with more conservative assumptions (see text).

TABLE 4. METHANE EMISSIONS BY INDUSTRY SEGMENT AND TYPE

Emission Type	Production Segment, Bscf ($10^9 m^3$)	Gas Processing Segment, Bscf ($10^9 m^3$)	Transmission and Storage Segment, Bscf ($10^9 m^3$)	Distribution Segment, Bscf ($10^9 m^3$)	Industry Emissions, Bscf ($10^9 m^3$)	Emissions as Percent of Total
Fugitive	24.0 ± 10.0[b] (0.68 ± 0.28)	24.4 ± 16.7 (0.69 ± 0.47)	72.1 ± 47.0 (2.04 ± 1.33)	74.7 ± 35.8 (2.12 ± 1.01)	195.2 ± 62.3 (5.53 ± 1.76)	62.1
Vented	53.8 ± 33.1 (1.52 ± 0.94)	5.1 ± 8.1 (0.14 ± 0.23)	33.0 ± 33.9 (0.93 ± 0.96)	2.2 ± 40.0 (0.06 ± 1.13)	94.2 ± 62.4 (2.67 ± 1.77)	30.0
Combusted	6.6 ± 13.2 (0.19 ± 0.37)	6.9 ± 8.9 (0.20 ± 0.25)	11.4 ± 1.8 (0.32 ± 0.05)	N/A	24.9 ± 16.0 (0.71 ± 0.45)	7.9
Total[a]	**84.4 ± 37.0 (2.39 ± 1.05)**	**36.4 ± 20.6 (1.03 ± 0.58)**	**116.5 ± 58.0 (3.30 ± 1.64)**	**77.0 ± 53.6 (2.18 ± 1.52)**	**314 ± 105**[c] **(8.89 ± 2.97)**	**100**

[a] Individual categories may not sum exactly to totals shown due to the roundoff of significant figures.
[b] Precision is based on a 90% confidence interval, assuming a normal distribution.
[c] Total precision is based on the upper limit of a 90% confidence interval, with more conservative assumptions (see text).

Our emission estimate of 314 Bscf (8892.5 x 10^6 m^3) is approximately twice the two previous estimates [16,17] for the U.S. gas industry. These previous studies were based on defensible methods of estimation but did not have a large amount of data available to them, and as a result, some large categories of emissions were underestimated. Most important among these categories was fugitive emissions. The most significant groups of fugitives responsible for differences in these studies are compressor components which account for 82 Bscf (2322.2 x 10^6 m^3) of the difference and distribution sources such as pipelines, meter and regulation stations, and customer meters, which collectively account for another 60 Bscf (1699.2 x 10^6 m^3) of the difference. The estimate produced in this study should provide a more reliable basis for decisions by modelers, policy makers, and industry alike.

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