EPA/600/A-92/279

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Inventory of Methane Losses from the Natural Gas Industry

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INTRODUCTION

This paper presents the second year's results of an ongoing four-year program undertaken jointly by the Gas Research Institute and the U.S. Environmental Protection Agency (EPA) to assess the methane losses from the U.S. natural gas industry. The program objective is to assess the acceptability of natural gas as a substitute for other fossil fuels for mitigating global climate change.

As shown in Figure 1, carbon dioxide (CO_2) is estimated to comprise more than half of the global warming potential created by current trace gas emissions. Figure 2 illustrates that fossil fuel combustion accounts for nearly three-quarters of the anthropogenic sources of CO_2 emissions. While reducing our reliance on fossil fuels would be the most effective means of mitigating combustion sources of CO_2, such a program would be costly and would take time to implement. In the interim, a mitigation program relying on the most environmentally efficient fossil fuel would be very beneficial. As shown in Figure 3, natural gas produces the least CO_2 per unit of energy output of all of the fossil fuels.

However, the production and transport of natural gas results in emissions of methane. As shown in Figure 1, methane is also considered a significant greenhouse gas. The benefits of reduced CO_2 emissions may consequently be outweighed by the methane loss from increased natural gas operations. Therefore, to resolve the issue of the acceptability of natural gas in the mitigation of global warming, the Gas Research Institute and the EPA have embarked on a detailed study of methane loss from the U.S. natural gas industry.

The scope of the program is to directly quantify methane losses from the three major segments of the natural gas industry: production, transmission, and distribution. The production segment comprises field production, gathering, and gas processing. The transmission segment includes sources such as transmission pipelines, meter and pressure regulating stations, odorant stations, compressor stations, and gas storage facilities. The distribution segment includes the underground distribution pipelines and above-ground facilities such as meter and pressure regulating stations associated with the distribution of natural gas to the consumer. The study does not address methane emissions from residential, commercial, or industrial end-use sources.

The emission source categories contributing to methane emissions include fugitive losses from valves, flanges, and equipment seals; vented losses from process vents, pneumatic equipment, compressor starts, and maintenance operations; combustion source flue gas losses; and losses due to upsets and

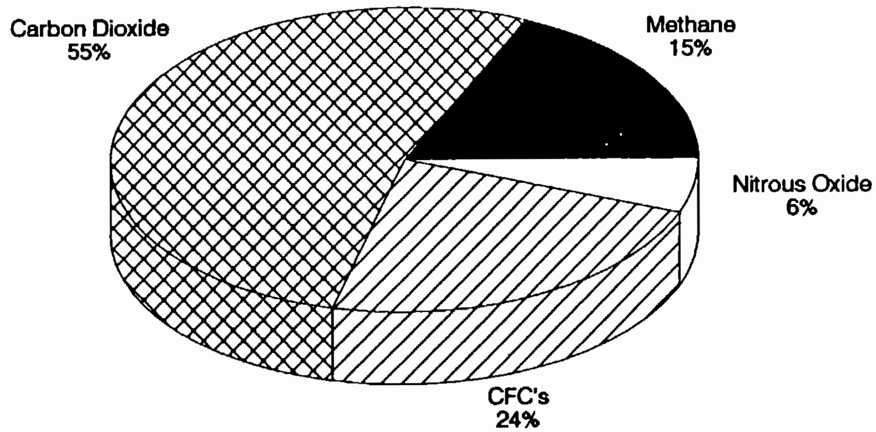

Figure 1. Contribution of Trace Gases to Global Warming (1980s)[1]

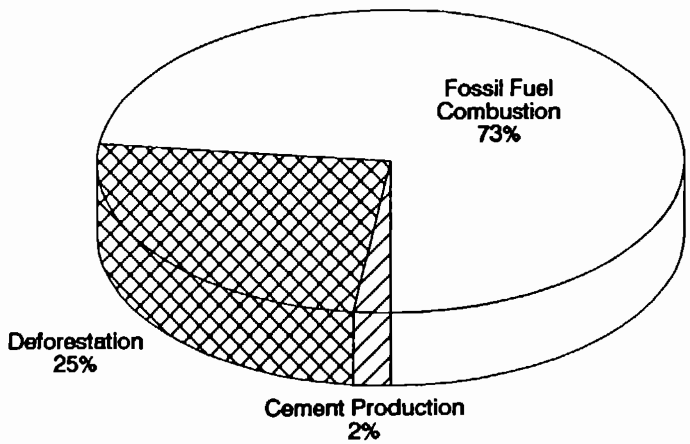

Figure 2. Anthropogenic Emissions of CO_2[2]

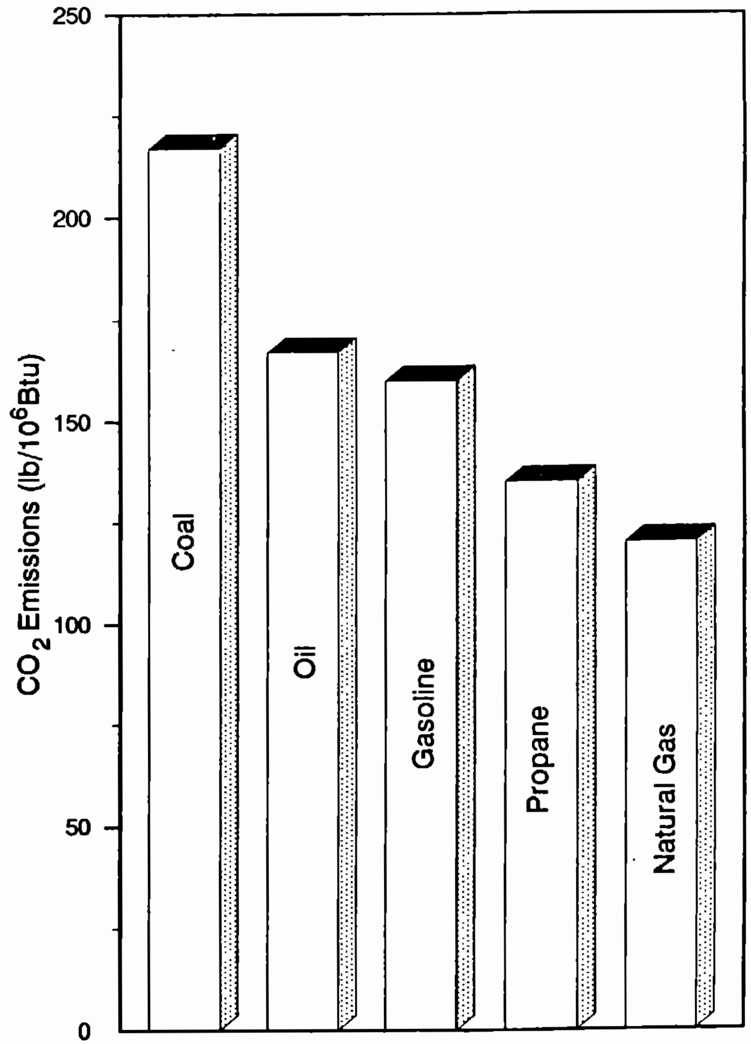

Figure 3. Carbon Dioxide Emissions from Fossil Fuel Combustion per Unit of Energy Output

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mishaps. Sources of methane loss from the production and transmission segments are being covered in two separate papers. Fugitive losses and vented gas from normal operations and routine maintenance activities are discussed in Paper No. 92-142.06. Methane emissions from the exhaust of reciprocating engines and gas turbines that are used to drive compressors for gas transport are presented in Paper No. 92-142.05.

Methane emissions from the gas distribution segment of the U.S. natural gas industry will be presented in this paper. In addition, this paper also presents a summary of the current estimate of total methane emissions from all sources within the natural gas industry.

DISTRIBUTION LEAK TEST PROGRAM

Scope

The distribution segment consists of both below- and above-ground sources. Methane leakage from underground distribution systems was initially estimated to be one of the largest emission sources from the gas industry. Consequently, a leakage measurement program was developed to quantify losses from this source. The objective of the cooperative leak test program is to estimate total annual natural gas leakage from below-ground gas distribution systems. The program consists of voluntary participation from nine U.S. gas distribution companies, two Canadian companies, and one distribution system from Northern Europe. The participants will perform leak tests to quantify mean leak intensity and implement a standardized leak survey to quantify leak frequency. The objective of the above-ground leak test program is to estimate total annual methane emissions from all above-ground gas distribution features. Emissions include fugitive losses and natural gas released during normal system operations and routine maintenance activities. The primary above-ground features include metering stations, pressure regulating stations, odorant stations, and customer meters.

The final products of the program include individual total leakage estimates for the program participants, an annual gas leakage estimate from the national distribution industry, and detailed documentation to assist other distribution systems in estimating leakage. The target accuracy of the estimate for each participating company is within 25 percent of the true value with a 90 percent level of confidence.

Approach

The calculated below-ground emission rate, expressed as standard cubic feet per hour (scf/hr)*, is the product of an emission factor and an activity

*Readers more familiar with metric units may use the following factors to convert to this system: 1 ft^3 = 0.028 m^3, 1 lb/10^6 BTU = 435 ng/J, 1 mi = 1.6 km, and 1 ft = 0.3 m.

factor. The emission factor is derived using the leak intensity and leak frequency estimates. The participating companies measure gas leakage intensity from underground mains by testing either individual leaks (units = scf/leak-hour) or pipe segments (units = scf/mile-hour). Leakage intensities from customer service lines are measured by isolating the entire length of service line (units = scf/service-hour). The general procedure for testing individual leaks entails selecting and centering the leak (without disturbing the soil surrounding the leak), isolating the short segment of pipe containing the leak, and measuring the gas rate required to maintain the isolated segment at normal operating pressure. This technique is based upon testing detectable leaks, and may exclude smaller or more diffuse leaks that are not detectable at the soil surface. The general procedure for testing entire segments of mains includes selecting the segment to be tested, isolating the segment, and measuring the gas rate required to maintain the segment at normal operating pressure. The resulting test data will represent a leakage intensity per length of main that includes all sources of leakage in the segment, even leaks that may not be detectable at the soil surface. The segment of pipe being tested will also be surveyed to determine the number of detectable leaks and the corresponding concentration of methane measured for each leak in the segment. The number of leaks found in the segment can then be used to estimate the average leakage rate per leak for an alternative comparison with the individual leak test results. Standardized test procedures and quality assurance/quality control (QA/QC) guidelines will be implemented by all program participants.

Leak frequency estimates are derived by implementing a standardized leak survey protocol over a selected portion of the distribution system. The rigorous leak survey procedure employs a calibrated portable flame ionization detector. Identical leak detection protocols will be implemented by the program participants. Any reading above 10 ppm requires further investigation. The concentration and location of the highest organic vapor analyzer (OVA) reading is recorded. These leak frequency data will be used to derive the number of total leaks per mile of main and per individual service for the sections surveyed. By comparing the results from the standardized leak survey procedure with existing company leak repair records, the leak frequency for the entire underground distribution system can be calculated. Leak duration will be factored into the leak frequency estimates for companies that employ a multiyear leak survey cycle. By combining the leak intensity and leak frequency estimates, an emission factor is developed (units = scf/mile-hour, or scf/service-hour).

Activity data are represented by the miles of main and the number of customer services maintained by the national gas distribution industry. Detailed activity data are provided by program participants, while industry-wide activity data are available from the U.S. Department of Transportation.

Many factors that influence below-ground natural gas leak rates were identified by industry experts and engineering judgments. The proposed experimental design for the leak test program evaluates the influences of seven independent variables. First, the design uses three primary factors (pipe use, pipe material, and pipe vintage) to stratify the participant group. The resultant strata are then further evaluated according to the influence of four secondary factors. Table I lists the primary and secondary factors and defines the discrete categories within these factors. Figure 4 shows the 16 primary test strata. Specific strata are omitted where material/age categories do not exist. The goal of this stratified, factorial design is to increase the accuracy of the stratum-specific and overall estimates by defining strata that did not contain as much variation as was observed over the entire population. The stratified approach is also needed to meet the target accuracy of the leakage estimates for the individual companies.

Using summary statistics from available leak test data and the desired accuracy of the final estimates, a minimum sample size of 200 leak tests has been calculated. A two-stage sampling scheme will be implemented to maximize the amount of information gained about the influencing factors, both primary and secondary, while effectively allocating the limited sample size. Stage-one sampling will initially assign 8 leak tests to each of the 16 strata presented in Figure 4, thus satisfying the requirements of the factorial design (n=128). The analysis of the stage-one data should indicate which primary and secondary variables are influencing gas leak rates. Based on the stage-one findings, stage-two leak tests will be allocated to specific strata to enhance stage-one analyses and to increase estimate precision (n=72).

The methane emission rate for above-ground facilities (units = scf/hr) is also the product of an emission factor and an activity factor. The emission factor is derived from point source tracer emission flux measurements conducted at the above-ground facilities of selected program participants. The tracer tests estimate natural gas emissions from selected above-ground features such as pressure regulating stations (units = scf/feature-hrs). The activity factors are the number of specific above-ground features in the U. S. natural gas industry. Activity data counts will be collected via surveys and site visits.

Individual tracer tests are performed on randomly selected above-ground facilities. The number of tests initiated on each category of above-ground features, while still undetermined, must be large enough to ensure a calculated precision that will meet the desired accuracy of the emission estimate.

Preliminary Findings

The assumption that the below-ground sample population (i.e., program participants) is representative of the target population (i.e., national distribution industry) is an important consideration in developing the experimental design, defining the appropriate sampling scheme, and assessing the accuracy of the leakage estimates. A comprehensive industry characterization analysis suggests that the 9 U. S. program participants are very representative of the national industry with respect to pipe material and pipe age. Figures 5 and 6 compare the 9 participants to the top 100 U. S. gas

TABLE I. Factors Influencing Leakage Rate From Below-Ground Distribution Systems.

Influencing Factor	Assigned Categories
Primary Factors	
Pipe Use	Main, Service
Pipe Material	Unprotected Steel Cathodically Protected Steel Plastic Cast Iron[a] Copper[b]
Pipe Vintage	Pre-1940, 1940-1969, 1970-1990
Secondary Factors	
Leak Detection & Repair Practices	Good, Fair
Gas Operating Pressure	High, Low
Soil Characteristics	Porous, Nonporous
Pipe Diameter	Large, Small

[a]Mains only.

[b]Services only.

MAINS

Age / Material	Pre-1940	1940-1969	1970-1990
Unprotected Steel			
Protected Steel			
Plastic			
Cast Iron			

SERVICES

Age / Material	Pre-1940	1940-1969	1970-1990
Unprotected Steel			
Protected Steel			
Plastic			
Copper			

(blank box) = Stratum included in design.

(shaded box) = Stratum omitted from design.

FIGURE 4. Leak Test Program Primary Strata.

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distribution systems. The ranking of the top 100 distribution systems is based on total miles of underground mains. The material and age information was provided by the U.S. Department of Transportation. These 100 distribution systems account for roughly 80 percent of the total national gas throughput. Figure 5 clearly shows that the relative proportions of distribution main pipe materials for the 9 companies are nearly equal to the proportions for the 100 companies. Figure 6 shows that the program participants are representative of the national population in terms of number of services broken down by pipe material. Figures 7 and 8 show that the pipe vintage classes within the program participants are representative of the age classes for the top 100 companies.

Four leak test program participants have collected preliminary leak rate data. Two companies used the segment testing method and the remaining two employed the individual leak test approach. The following preliminary national emission estimates are based on 37 main leak tests and 30 service tests.

The estimated national leak rate from underground mains is just under 2×10^6 scf/hr. The data suggest that plastic mains contribute approximately 16 percent to the total hourly emissions. The protected and unprotected steel mains account for roughly 10 percent and 8 percent, respectively. Cast iron mains make up possibly as much as 65 percent. The estimated national leak rate from underground services is approximately 3×10^5 scf/hr. Unprotected steel services contribute over 65 percent to the total hourly emissions. Cathodically protected steel and copper each accounts for roughly 15 percent of the total, while plastic services make up approximately 2 percent.

Total annual emissions from underground main leaks are approximately 16×10^9 scf per year. Total annual emissions from below-ground service leaks are approximately 3×10^9 scf per year.

Significant uncertainty is associated with nearly all of the leakage estimates. The 90 percent confidence interval for each material-specific estimate, except protected steel services, includes a leak rate of 0 scf/hr, suggesting that additional data points must be collected to increase the precision around the calculated emission totals for mains and services.

The reported emission totals for each of the pipe material classes will shift as more leak test data are collected. The protected and unprotected steel classes, for both mains and services, have an adequate preliminary sample size. It is likely that additional leak tests in the steel groups will increase the precision of the estimated leak rates. The plastic mains and services, while potentially maintaining a very low leak frequency, will likely have a large variation in leak intensity. Additional data collection in the plastic classes is required to increase the precision of the estimated leak rates. Cast iron mains are unique in the study of below-ground pipes in that leaks typically originate from joints. Cast iron is very resistant to corrosion. Depending on the age and the specific type of iron, bell and spigot joints are at uniform intervals (e.g., 12, 16, and 18 feet).

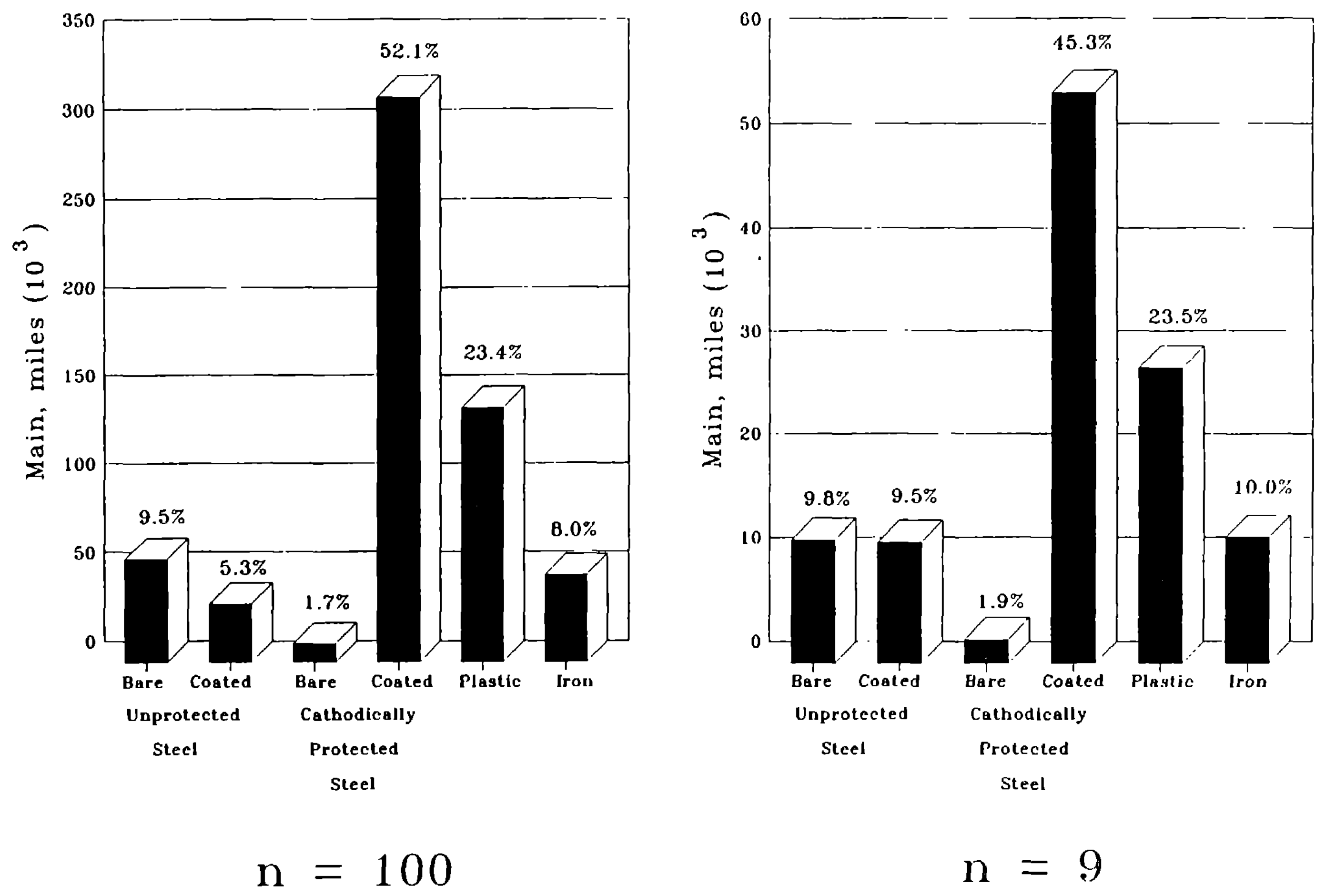

FIGURE 5. Comparison of Top 100 Companies and Program Participants for Miles of Main Broken Down by Pipe Material.

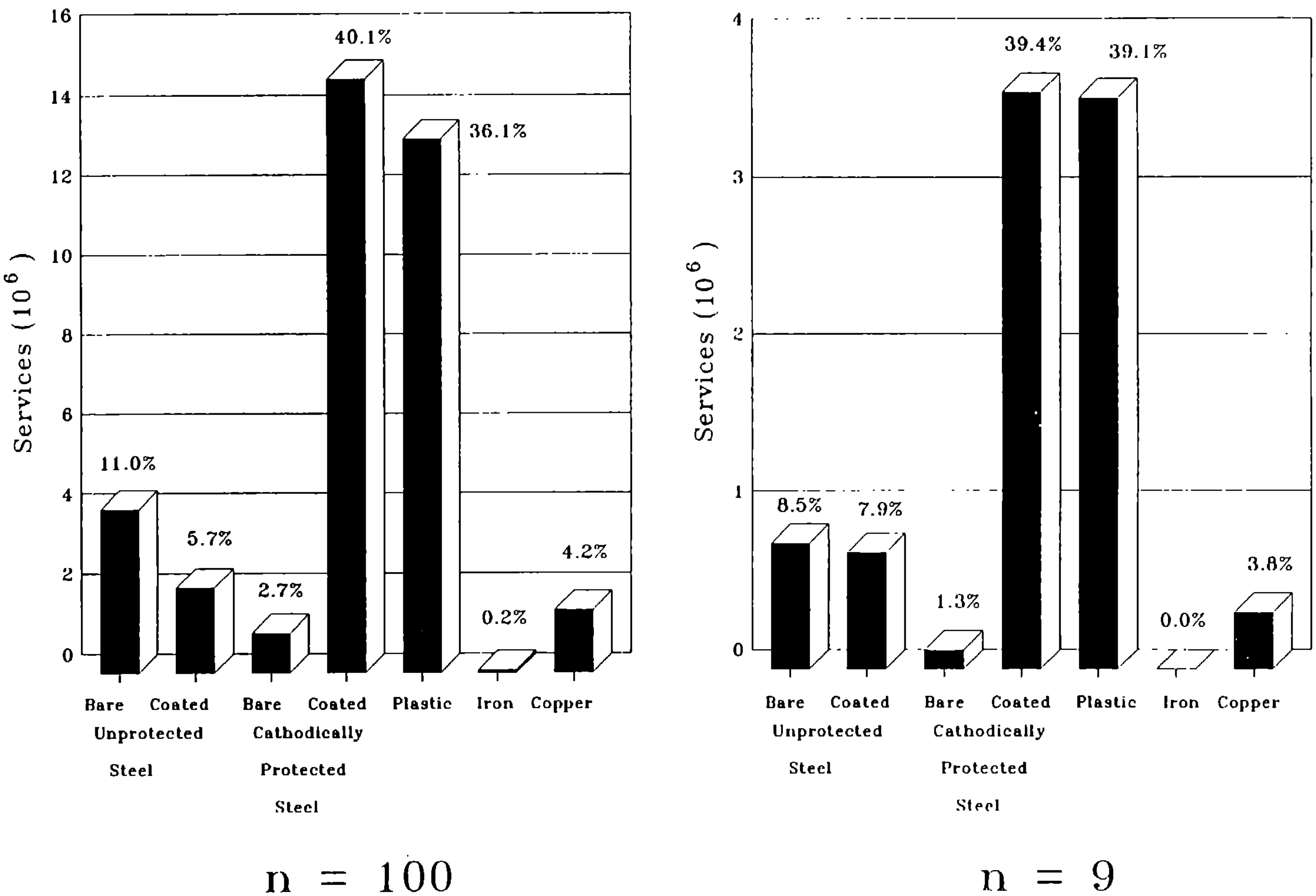

FIGURE 6. Comparison of Top 100 Companies and Program Participants for Number of Services Broken Down by Pipe Material.

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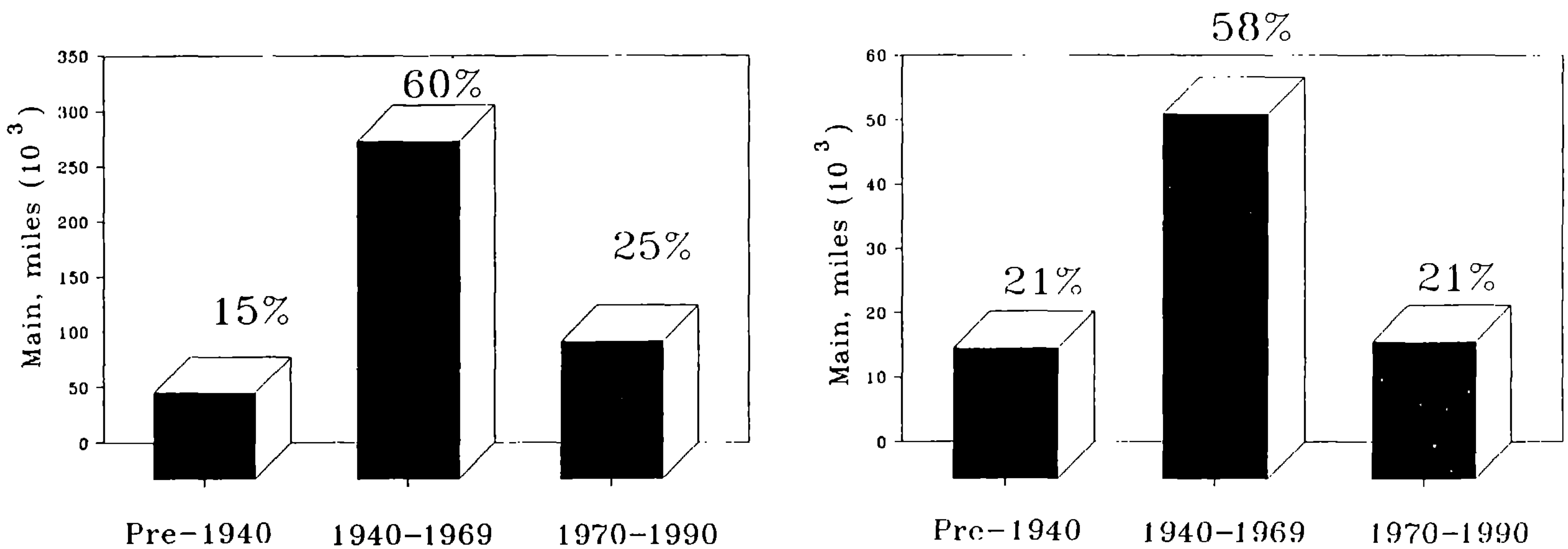

n = 100

n = 9

FIGURE 7. Comparison of Top 100 Companies and Program Participants for Miles of Main Broken Down by Proposed Age Intervals.

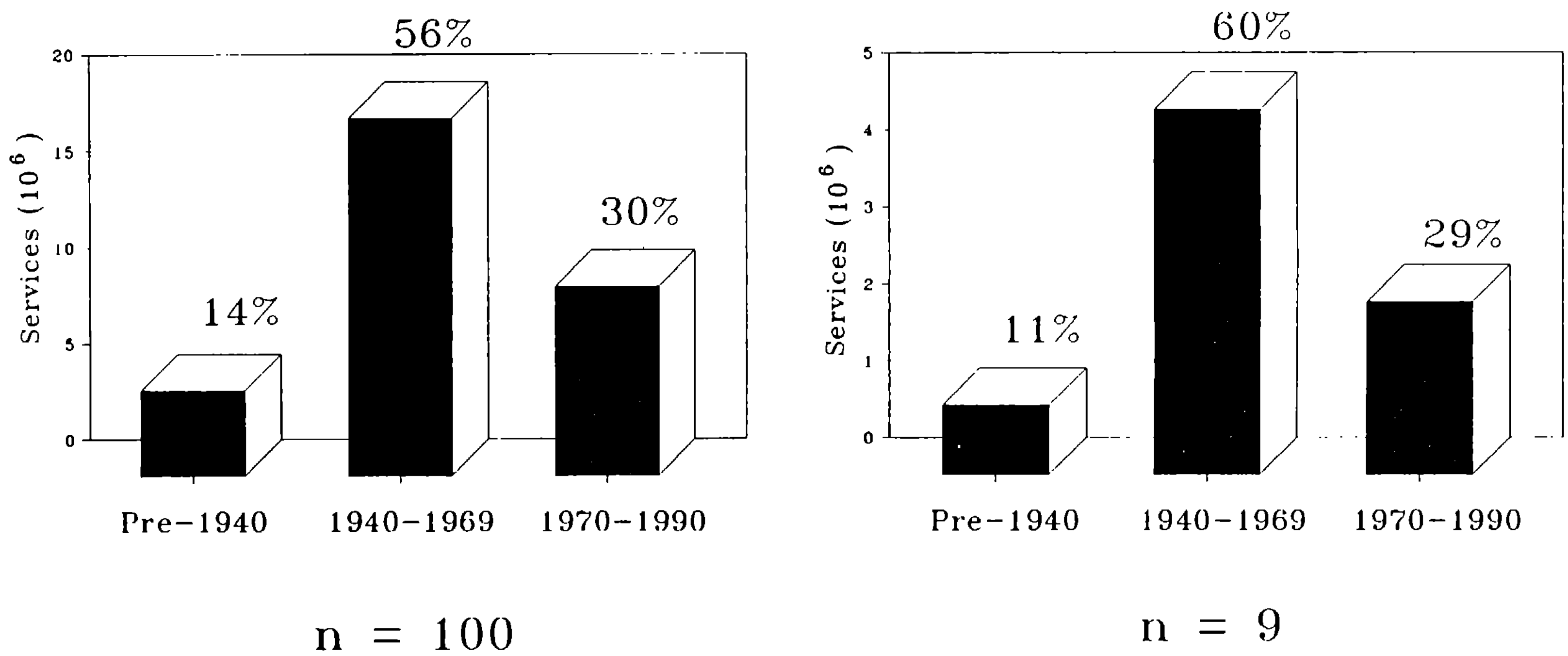

FIGURE 8. Comparison of Top 100 Companies and Program Participants for Number of Services Broken Down by Proposed Age Intervals.

Therefore, estimating the leak rates from cast iron mains may require a unique approach. For example, cast iron leak frequency calculations will depend on the specific segment lengths (i.e., joint interval) and past repair or replacement programs.

The national emission estimates presented above are based on leak frequencies calculated from reported leak repair records. Unrepaired leaks and undetected leaks are not included in these preliminary leak frequency estimates. Therefore, the reported values may underestimate total annual emissions. The leak repair frequencies were scaled up to account for multiyear leak survey cycles. Many of the larger distribution companies must employ multiyear leak detection and repair programs. The leak test program will adjust leak frequency estimates for companies with multiyear leak survey cycles.

This discussion of uncertainty is intended to discourage the perception that the presented emission totals are accurate estimates of natural gas leakage from below-ground distribution systems. These preliminary estimates are presented as part of an overall introduction to the cooperative leak test program. The proposed experimental design will build on these available data to estimate annual natural gas leakage from underground pipes.

Initial estimates of above-ground leakage are based on 13 point source tracer tests performed in four midwestern cities and three southern plain cities. The tests are limited to distribution system metering and pressure regulating stations. The calculated emission factor is approximately 10 scf/station-hr, with a standard error of over 3 scf/station-hr. Based on U.S. Department of Transportation data and a frequency estimate from two gas companies, an estimated 1.4×10^5 regulator stations are operating across the U.S. gas distribution network. The preliminary above-ground emission estimate is approximately 12×10^9 scf of methane per year with a standard error of 4×10^9 scf per year.

INDUSTRY TOTAL LOSSES

As part of the overall program to quantify methane losses, a preliminary assessment of actual emissions has been made for each individual segment of the gas industry. Because of the complexity of the gas industry, an effort was made to prioritize the research activities. Therefore, a preliminary estimate of emissions from each source was made to focus the research in accordance with the relative importance of the source to the national total loss. The total methane emissions from the U.S. natural gas industry were estimated to be approximately 200×10^9 scf/yr.

The sources of emissions were classified according to their associated segment of the industry. The industry segments include gas production, gathering systems, gas processing plants, transmission systems, storage facilities, and distribution systems. Gas production and gathering consist primarily of gas and oil wells, field separation equipment, gas compressors used in production, and gathering pipelines. Gas processing plants comprise all process operations associated with natural gas purification and transport to transmission custody. The gas transmission segment includes compressor stations, transmission pipelines, odorant facilities, and above-ground meter and pressure regulating stations. Distribution systems consist of the underground main and service pipelines and above-ground facilities such as meter and pressure regulating stations.

Emission estimates were divided into two broad categories based on the inherent characteristics of the source. The first category, fugitive emissions, includes continuous leakage from equipment components such as valves, flanges, and pump and compressor seals, as well as leakage from underground pipelines. As shown in Table II, emission estimates from fugitive sources in each segment of the gas industry account for approximately half of the total industry emissions.

Fugitive emissions for most segments of the industry were estimated by average component counts based on model facilities and the use of fugitive emission factors. Preliminary emission factors developed based on ongoing bagging and screening studies by API/Star Environmental for offshore and onshore oil and gas production and gas plants are currently being used to estimate fugitive emissions. Above-ground emission sources from transmission and distribution systems, such as meter and pressure regulating stations, were estimated using interim data supplied by Aerodyne/Washington State University based on a tracer technique to quantify methane loss. These studies will be completed in 1993. Fugitive losses from underground transmission and distribution pipelines were estimated based on leak test data from four gas distribution companies in the United States. Leakage from underground distribution services and mains was estimated to be the most significant contributor to fugitive losses in the industry.

The second broad category of emissions, non-fugitives, includes all intermittent losses directly to the atmosphere or to a flare. Non-fugitive sources are more difficult to measure because of the intermittent nature of the emissions. Non-fugitive emissions may occur during normal operations of some equipment, during routine maintenance activities where gas is purged from the system, or during process upsets and mishaps. Non-fugitive sources also include exhaust emissions from combustion engines and turbines used to drive compressors. The total emissions estimate from all non-fugitive sources in the industry accounts for approximately half of the total national estimate.

Both fugitive and non-fugitive estimates for each segment of the industry are significant as shown in Table II. Estimated losses from the gas production and gathering operations are the largest in the industry, followed by transmission and storage. Losses from gas plants and the distribution segment are significantly lower; however, the uncertainty in the emissions estimate from gas plants and distribution is substantial.

Table II. Methane Emissions from
U.S. Natural Gas Industry

Industry Segment	Methane Emissions (percent of total) Fugitive	Venting/Flaring/Upsets
Production and Gathering	13	26
Processing Plants	5	5
Transmission and Storage	13	19
Distribution	17	2
TOTAL (percent)	48	52

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ACKNOWLEDGEMENTS

This project was cofunded by the Gas Research Institute, Chicago, Illinois, and the Office of Research and Development, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina. Radian gratefully acknowledges the contribution made by the sponsors.

AEERL-P-922

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before complet

1. REPORT NO. EPA/600/A-92/279	2.	3.
4. TITLE AND SUBTITLE Inventory of Methane Losses from the Natural Gas Industry		5. REPORT DATE 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) M. V. Campbell, L. M. Campbell, and C. E. Burklin		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Radian Corporation, P.O. Box 13000, Research Triangle Park, North Carolina 27709		10. PROGRAM ELEMENT NO. 11. CONTRACT/GRANT NO. 68-D1-0031
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development, Air and Energy Engineering Research Laboratory, Research Triangle Park, North Carolina 27711		13. TYPE OF REPORT AND PERIOD COVERED Published paper; 10/91-4/92 14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES AEERL project officer is David A. Kirchgessner, Mail Drop 63, 919/541-4021. For presentation at AWMA Conference, Kansas City, MO, 6/22-26/92.

16. ABSTRACT The paper gives the second year's results of an ongoing 4-year program undertaken jointly by the Gas Research Institute and the U.S. EPA to assess the methane (CH4) losses from the U.S. natural gas industry. The program's objective is to assess the acceptability of natural gas as a substitute for other fossil fuels for mitigating global climate change. The scope of the program is to directly quantify CH4 losses from the three major segments of the natural gas industry: production, transmission, and distribution. The study does not address CH4 emissions from residential, commercial, or industrial end-use sources. The paper covers CH4 emissions from the gas distribution segment of the natural gas industry. Methane losses from the production and transmission segments are covered in other papers. In addition, this paper summarizes the current estimate of total CH4 emissions from all sources within the natural gas industry.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Pollution Control	13B
Methane	Stationary Sources	07C
Natural Gas	Methane Losses	21D
Gas Distribution	Global Climate	15E

18. DISTRIBUTION STATEMENT Release to Public	19. SECURITY CLASS (This Report) Unclassified	21. NO. OF PAGES 17
	20. SECURITY CLASS (This page) Unclassified	22. PRICE

EPA Form 2220-1 (9-73)