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Date of Hearing: April 11, 2019

Case No. 16-0253-BTX

PUCO Case Caption:

In the Matter of the Application of Duke Energy Ohio, Inc.; for a Certificate of Environmental Compatibility and Public Need for the C314V Central Corridor Pipeline Extension.

Volume III

List of exhibits being filed:

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City/County 2-12, 14-26, 28, 30-42

Reading 3, 4

Reporter's Signature: Karen Gibson

Date Submitted: 4-12-2019

BEFORE THE OHIO POWER SITING BOARD

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In the Matter of the :
Application of Duke Energy :
Ohio, Inc., for a :
Certificate of Environmental: Case No. 16-0253-GA-BTX
Compatibility and Public :
Need for the C314V Central :
Corridor Pipeline Extension :
Project. :

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PROCEEDINGS

before Ms. Greta See and Ms. Sarah Parrot, Administrative Law Judges, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 9:10 a.m. on Thursday, April 11, 2019.

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VOLUME III

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American Gas Foundation

Safety Performance and Integrity of the Natural Gas Distribution Infrastructure

January 2005

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EXHIBIT
NOPE 13

Safety Performance and Integrity of the Natural Gas Distribution Infrastructure

Prepared for the American Gas Foundation by:

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American Gas Foundation

Founded in 1989, the American Gas Foundation is a 501(c)(3) organization that focuses on being an independent source of information research and programs on energy and environmental issues that affect public policy, with a particular emphasis on natural gas. For more information, please visit the website at www.gasfoundation.org or contact Gary Gardner, Executive Director, at 202.824-7270 or ggardner@gasfoundation.org.

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Foreword

This report was sponsored by the American Gas Foundation (AGF) to provide an independent technical insight into natural gas distribution system integrity features and safety performance over the period 1990 to 2002. To perform the technical work, the Foundation awarded a contract to URS Corporation of Chicago, IL. The study entitled *Safety Performance and Integrity of the Natural Gas Distribution Infrastructure* was thus started in October 2003, under the direction of the Foundation, with guidance from an advisory group, the Distribution Integrity Steering Group (DISG) that was formed by the Foundation in support of this study.

At the same time, realizing that gas distribution also involves municipal gas systems, the American Public Gas Association (APGA) was invited to participate on the Foundation's advisory group. Since gas distribution systems are, with a few exceptions, under state regulatory authority, the Foundation reached out to the National Association of Pipeline Safety Representatives (NAPSR) and the National Association of Regulatory Utility Commissioners (NARUC) to invite them to participate in providing input on the direction and areas of focus of the study. The Distribution Infrastructure Government-Industry Team (DIGIT) was formed, including members from the Foundation, APGA, NAPSR, NARUC and also the U.S. Department of Transportation's (DOT) Research and Special Programs Administration, Office of Pipeline Safety (OPS), which participated as an observer in the team's proceedings. The DIGIT met for the first time in January 2004 and through a consensus process, guided *Safety Performance and Integrity of the Natural Gas Distribution Infrastructure* to completion. Obtaining consensus involved review and input by the represented participating organizations.

The Foundation is deeply grateful to the members of this team as well as to the members of the organizations that contributed by providing input to this important study. The Foundation also would like to acknowledge Mike Musial, Glenn DeWolf, Doug Orr, Julie Martin, and Pilar Odland at URS Corporation for their outstanding work in writing this report.

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February 9, 2005

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Dear Mr. Gardner:

The National Association of Pipeline Safety Representatives (NAPSR) participated in oversight of the American Gas Foundation (AGF) study, **Safety Performance and Integrity of the Natural Gas Distribution Infrastructure**, through the Distribution Infrastructure Government-Industry Team (DIGIT). DIGIT was formed after the AGF study was underway following an initial scope definition and the awarding of a contract. However, DIGIT was able to subsequently influence, to some degree, the direction and scope of the study. Within the DIGIT's charter, NAPSR's participation was intended to help assure that the concerns of safety regulators were addressed, that the report was balanced, and that its conclusions were adequately supported. NAPSR believes that the AGF Study, in the majority, has resulted in a balanced report with supported conclusions while addressing the concerns of safety regulators. However, NAPSR does have the following conclusions and comments regarding the AGF study:

NAPSR believes that the gap analysis in the AGF report considers only whether existing regulations or practices address all threats applicable to distribution pipeline systems, not whether these are sufficient or broadly applied throughout the industry. The report concludes regulations and practices do exist that address all applicable threats. This conclusion is useful, but not sufficient. Further work could help clarify gaps between current regulations and practices and characterize actions needed to provide an increased level of safety assurance.

Given the scope of the AGF effort, NAPSR concludes that, while the resulting study is a useful first step, there is a need for additional work.

NAPSR recommendations that were outside the scope of this study need to be addressed by additional work.

NAPSR concludes that this study represents a useful snapshot of some of the factors that could be important in assuring the integrity of gas distribution pipeline systems. However considering the limits of its scope, it should only serve as background for future work needed to identify additional regulatory actions to provide necessary additional safety assurance.

NAPSR would like to extend its appreciation for the ability of NAPSR members to participate in this important study and for the willingness of the AGF to consider the comments and recommendations of DIGIT while developing the **Safety Performance and Integrity of the Natural Gas Distribution Infrastructure** report.

Sincerely,

Edward M. Steele

Edward M. Steele
NAPSR National Chairman

EMS:th

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Executive Summary

The purpose of this study, entitled *Safety Performance and Integrity of the Natural Gas Distribution Infrastructure,* is to provide an independent technical review of safety performance and integrity in the natural gas distribution sector through (1) a **detailed analysis** of the natural gas distribution industry's safety performance; (2) an **overview of current regulations and industry practices** that address threats to the natural gas distribution infrastructure; (3) a **description of the unique characteristics** that differentiate natural gas transmission pipelines from distribution pipelines; and (4) **identification of industry and government initiatives** that are currently in-place to ensure continual improvement in regulation and practices affecting distribution integrity.

Detailed Analysis - The safety performance review involved a detailed analysis of distribution incidents in the U.S. Department of Transportation (DOT), Office of Pipeline Safety (OPS), reportable incident database adopting an approach different from traditional approaches used by others in the past. Rather than considering all of the incidents in the OPS database, the study approach focuses on Serious Incidents, defined in the study as incidents that involved fatalities and injuries, and then uses statistical analysis to evaluate, at set confidence levels, whether an upward or downward trend in the data could be determined.

Overview of Current Regulations and Industry Practices - The results of a survey of a group of gas utility operators were used as the basis for the assessment of how threats to distribution system integrity are currently addressed both through pipeline safety regulations and industry practices. To serve as a representative cross section of the gas utility industry, the survey group was selected through guidelines established by the American Gas Foundation (AGF), state utility and service commission safety representatives, and the American Public Gas Association (APGA).

Description of The Unique Characteristics - Input from the survey group, together with knowledge and experience of personnel on this project and with review by a government and industry study oversight team, provided a comprehensive review of key integrity-related differences between natural gas distribution systems and gas transmission pipelines.

Identification of Industry and Government Initiatives - Industry group member input together with available data on recent federal programs and initiatives, provided the information needed to identify current programs and initiatives that have the potential to promote continual improvement in practices, procedures and processes used to address gas distribution infrastructure integrity.

Major Findings

Distribution Safety Performance

- Over the study period from 1990 through 2002, there has been a statistically determined downward trend in "Serious Incidents", namely those involving a fatality or an injury. The amount of the decrease in the trend is approximately 40%.
- Outside force damage to the infrastructure was the major cause of Serious Incidents during the study period. This incident category in the OPS database is responsible for 47% of the 601 Serious Incidents involving distribution facilities. The data show a statistically determined decreasing trend, with a decrease of approximately 50%.
- The predominant component of outside force damage was third party damage, (typically excavation damage inflicted on distribution facilities by a third party not related to the gas system operator or its surrogate), contributing nearly 35% to the total number of the Serious Incidents.
- Of the other incident categories in the OPS database, Corrosion caused only 6.5% of Serious Incidents; Construction/Operating Error and Accidentally Caused by Operator categories each accounted for less than 10% of the Serious Incidents.
- Of the total 601 Serious Incidents, 46% occurred on distribution mains, while 34% of the incidents occurred on service lines and meter sets combined. The remaining incidents were categorized by operators as "Other" or "No Data".
- The Mann-Kendall (M-K) test was used to identify whether a statistically significant decreasing or increasing trend may exist for a given data set. No upward trends were validated.
- A number of gaps in the OPS data were identified that preclude a deeper insight into the mechanisms by which specific threats affect the integrity of distribution pipelines.
- Normalized by 100,000 miles over the study period, the average fatality and injury counts for gas distribution are essentially the same as the counts for gas transmission.

Distribution Infrastructure Integrity

Based on a survey of a representative cross-section of gas distribution companies, the following significant findings were compiled.

- Operators use additional prevention and mitigation measures that exceed the requirements of the federal pipeline safety regulations to address specific threats to the integrity of distribution pipelines. The measures used are generally consistent with the perceived significance of the threat as indicated in the industry practices survey results.

- The top five processes identified by the survey group as having the highest impact on distribution integrity are: (1) cathodic protection systems; (2) leak surveys; (3) operator qualification programs; (4) one-call systems; and (5) planned pipe replacement programs. The programs and processes in this group are consistent with indications from the incident statistics.

- Operators address the dominant threat of third party damage with prevention and mitigation measures that include those required to meet regulation -mandated pipeline safety requirements and additional ones that exceed the regulatory requirements.

- Over 80% of the operators in the survey reported employing risk-ranking tools to evaluate their distribution infrastructure.

- Over 65% of the companies that participated in this study have planned replacement programs for cast iron and almost 80% have such programs for bare steel.

- Pipe replacement between 1990 and 2002 has reduced the amount of cast iron main mileage by 21% and the amount of bare, unprotected steel main mileage by 7%. During the same period, the number of bare, unprotected steel services has been reduced by 13%.

- From the operator responses received, no apparent gaps were identified between specific threats to distribution integrity and the industry practices that address the threats.

- The respondents to the survey did not identify any apparent gaps between the pipeline safety regulations and any of the threats to the distribution infrastructure.

1.0 INTRODUCTION

Over the past few years, Pipeline Integrity Management regulations have been implemented for pipelines transporting hazardous liquids (Title 49 Code of Federal Regulations, CFR Section 195.452) and natural gas transmission pipelines (Title 49 CFR 192 – Subpart O).

Pipeline safety is of paramount importance in pipeline systems. This study was undertaken to examine some important aspects of the safety performance of the distribution natural gas pipeline infrastructure. The safety performance review involved a detailed analysis of distribution incidents reported to the OPS under the federal pipeline regulations. The analysis used a formal statistical test to identify trends in incident frequency for the period 1990 through 2002. The source material "Natural Gas Distribution Incident Data - mid 1984 to Present" comes from statistics on the OPS website at http://ops.dot.gov.

Originally, the period considered for the review was from 1985 through 2002. Starting in 1985 was considered because it provided the starting point in two previous safety studies; "Analysis of OPS Reportable Incidents for Gas Transmission and Gathering Lines – January 1, 1985 Through December 31, 1994" Kiefner and Associates, Inc, dated May 1996 and "The Safety Performance of Natural Gas Distribution Systems", Allegro Energy Group, dated February 2001.

Initial compilation of the OPS incident data from 1985 to 2002 indicated a relatively high level of incidents starting in 1985 through approximately 1992. Since OPS changed the property damage-reporting threshold in 1985 from $5,000 to $50,000, the DIGIT agreed with AGF that further scrutiny be applied to the number of incidents in the OPS database. A cursory review of the 1985-1989 incidents indicated the database might contain an unusually high, but decreasing, number of incidents in a category that does not involve the portion of the gas delivery system that falls under the jurisdiction of federal or state pipeline safety codes. In addition, it appeared that some incidents at the lower property damage threshold were still being reported. Based on these findings, the DIGIT recommended that the study focus on the incidents that occurred from 1990 through 2002. In addition, DIGIT agreed with the AGF proposal that the study only analyze incidents that involved fatalities and/or injuries (F&I), eliminating all incidents only involving property damage or those reported as "significant" in the judgment of the operator. This reduces the subjectivity in the incidents reported. These F&I incidents are referred to in this report as "Serious Incidents".

The review included an evaluation of reportable incidents by part of system (mains, services lines, meter set assemblies, and other), and by apparent cause (corrosion, damage by outside forces, construction / operating error, accidentally caused by operator, and other). Both of the above categories (by part of system and by cause) were also evaluated by material of construction (steel, polyethylene, cast iron and other). The statistics for bare, cathodically protected or unprotected steel, and for coated cathodically protected or unprotected steel were not analyzed separately because there are insufficient details in the database that distinguish these characteristics for steel pipe incidents.

An industry practices survey of a representative group of operators of various sizes was also conducted. The purpose of the survey was to identify current regulations and industry practices intended to address the causes of distribution infrastructure incidents. In addition, the study examined if gaps existed between industry practices and government regulations in addressing incident causes. It should be noted that the scope of the survey did not address the adequacy of the regulations and industry practices in preventing incidents and did not include a survey of government regulators.

Additionally, the study included a review of some of the important differences between natural gas transmission pipelines and distribution systems in order to better understand why there might be differences in safety performance. Finally, the study also sought to identify gaps in data, regulations, or practices that need to be closed in order to enhance distribution infrastructure safety. This included capturing the industry and government initiatives that are currently in-place that ensure continual improvements in data collection, regulations and practices for safety enhancement. A number were identified as legislative mandates, regulatory actions and voluntary industry programs.

2.0 BACKGROUND

Natural gas pipeline distribution systems are a vital part of the nation's energy infrastructure. These systems are the final stage of safe and reliable gas delivery to the nation's natural gas commercial, industrial and residential customers. The nation's distribution system comprises approximately 1.9 million miles of piping, which in 2002 included approximately 1.1 million miles of mains and 0.8 million miles of service lines: The mileage of distribution mains and services exceeds that of transmission pipelines by a factor of about six.

Operators[1] manage the integrity of natural gas distribution systems through compliance with Title 49 Code of Federal Regulations (49 CFR) Part 192 and, if applicable, all state and local pipeline safety regulations, orders, and directives that exceed the federal requirements. The industry practices survey revealed that individual operators use the regulations as a guide for evaluating whether additional prevention and mitigation measures should be employed, to improve the overall integrity and reliability of their specific distribution systems.

The U.S. Department of Transportation, Research and Special Programs Administration (RSPA), Office of Pipeline Safety (OPS), collects and maintains data on these systems through annual reporting requirements of the pipeline operators[2]. These data include overall mileage on these systems and data on reportable incidents. In 2002, over 1,300 distribution system operators submitted annual reports to OPS. These operators, and more than 9,000 master meter operators, comprise the nation's natural gas distribution industry, which serves over 66 million customers.

One of the performance measures for monitoring continuous improvement in the safety of the distribution infrastructure is incident history over time. In accordance with 49 CFR Part 191, operators are required to report certain incidents associated with their natural gas distribution systems to OPS. This incident information is then compiled by OPS and entered into an incident database that is publicly available on the OPS web site at http://ops.dot.gov. Pipeline incidents that meet one or more of the following criteria are stored in the OPS database: (1) an incident that resulted in a fatality or injury necessitating in-patient hospitalization; (2) property damage (including the cost of gas lost) of the operator or others, that was $50,000 or more; (3) an event that results in an emergency shutdown of a liquefied natural gas facility; or (4) the operator determined that the incident was important enough to report (see 49 CFR Section 191.3-Definitions). It should be noted that the property damage criteria was changed in 1985 from $5,000 to the current $50,000. This database is the primary publicly available database of pipeline incident failure statistics and records causes and consequence data from operator incident reports. This database and pipeline mileage information contained in the annual reports submitted to OPS is the foundation bases for the safety performance analysis of this report.

[1] 49 CFR Part 192 defines "Operator" as a person who engages in the transportation of gas

[2] RSPA F 7100.1-1 Annual Report for gas Distribution System and RSPA F 7100.1 Incident Report for Gas Distribution System.

3.0 TRANSMISSION PIPELINES AND DISTRIBUTION INFRASTRUCTURE

3.1 Purpose and Scope

This section discusses some of the differences between transmission and distribution pipelines, including the differences in system pressures, materials, failures mechanisms, inspections, and incident statistics. The majority of the assertions in this section are based on discussions with operators and representatives of the AGF.

The scope of this comparison is confined mainly to technical aspects and selected safety performance indicators. Not included are many of the non-technical aspects unique to distribution, such as impact on customers, operator-state relationships, and cost recovery, which are integral parts of the gas delivery process that are affected whenever significant regulatory or legislative actions result in changes to utility compliance requirements.

3.2 Infrastructure Differences

Some of the differences between transmission pipelines and distribution systems relate to the infrastructure. The characterizations in this section are primarily based on the annual reports operators submit to the OPS, and incident report data in the OPS Gas Distribution Incident Data database. These incident data are available directly from the OPS website at http://ops.dot.gov.

3.2.1 Basic Configurations

The natural gas delivery pipeline infrastructure is divided into gathering, transmission, and the distribution systems. The distribution system consists of mains, service lines and meter set assemblies. The latter facilities comprise meters, regulators and other installations. These systems are illustrated in Figure 3-1. This illustration is for descriptive purposes and is not necessary faithful to all jurisdictional aspects and definitions under the pipeline safety regulations.

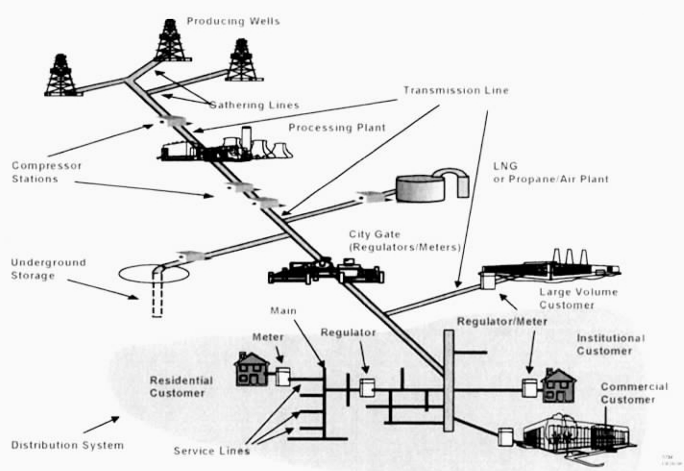


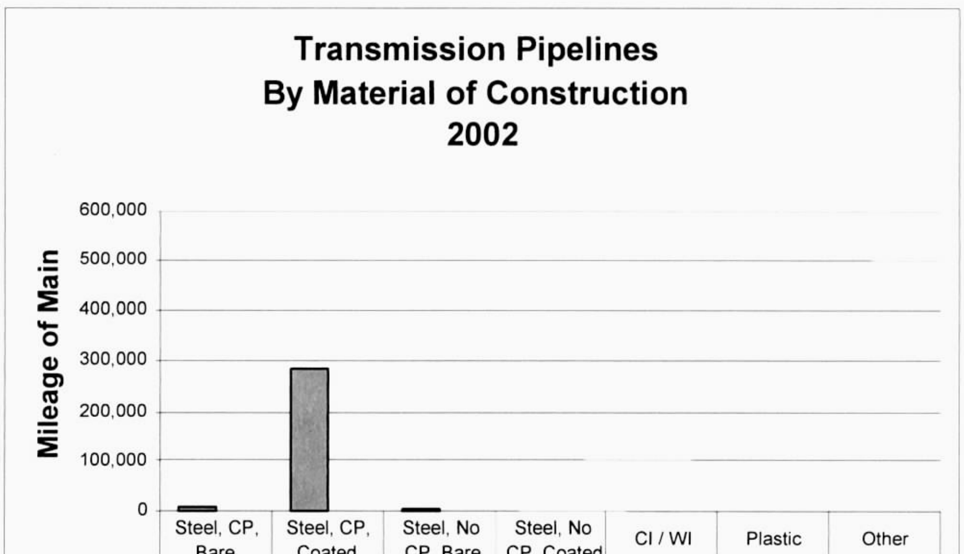
Figure 3-1. Schematic of the Natural Gas Delivery Pipeline Infrastructure

Transmission pipelines are typically linear systems that transport gas over a relatively long distance. These systems have relatively few, if any, connections on the main lines.

Distribution pipeline systems are arranged in network configurations to fit the geographical configuration of the service area. There are many connections on the main lines. Networks can be designed in branch or tree configurations, be redundant or supplied by a single feed. Because of the interconnections, each section of pipe could receive its gas flow from more than one direction. A distribution system can be subdivided into pressure districts, where each district is operated at its own pressure level to ensure adequate and reliable supply of gas to the area's customers.

3.2.2 Piping Materials of Construction

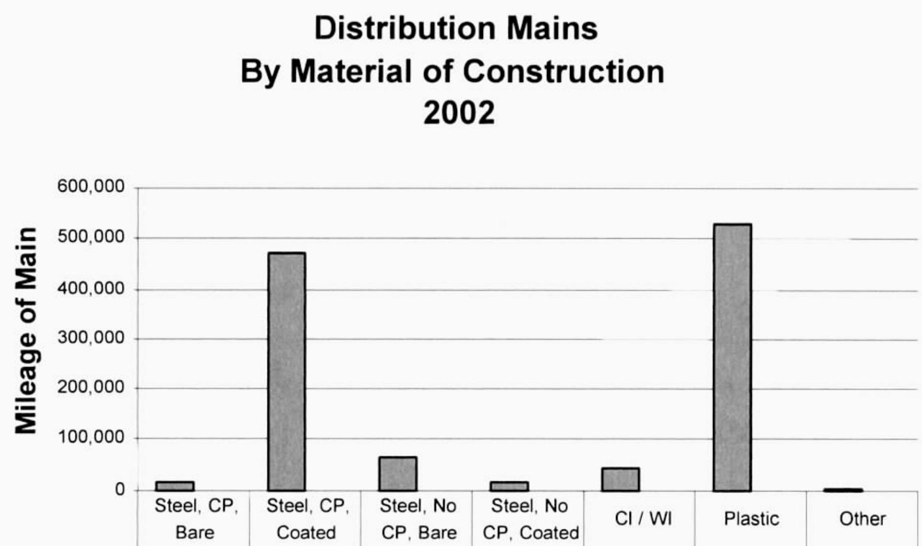
As Figure 3-2a demonstrates, transmission pipelines are constructed from only a few materials of construction. Nearly 100% of transmission pipelines are steel pipelines, according to data reported by operators on the 2002 annual reports. Over 96% of the total transmission mileage is wrapped/coated steel pipe that is cathodically protected. Approximately 3% of the total transmission mileage is bare steel with and without cathodic protection.



	Steel, CP, Bare	Steel, CP, Coated	Steel, No CP, Bare	Steel, No CP, Coated	CI / WI	Plastic	Other
Mileage	7,572	286,390	2,519	536	36	634	111
% of Total	2.5%	96.2%	0.8%	0.2%	0.0%	0.2%	0.0%

Figure 3-2a. Materials of Construction Transmission Pipelines Totals

Distribution systems are not as homogeneous as transmission systems in the piping materials used. Distribution mains are almost evenly divided between steel pipe (49.8% of the total) and polyethylene plastic pipe (45.9%). Cast iron and wrought iron (CI/WI) pipe accounts for 4.0% of the total. Many of the cast iron systems are left over from the days of manufactured gas distribution and have been operated for many decades at pressures from 0.25 psi to 60 psi. Figure 3-2b shows the distribution of materials of construction for Distribution Mains as reported by operators on their 2002 Annual Reports.



	Steel, CP, Bare	Steel, CP, Coated	Steel, No CP, Bare	Steel, No CP, Coated	CI / WI	Plastic	Other
Mileage	15,338	472,329	64,662	17,948	45,523	525,959	3,227
% of Total	1.3%	41.3%	5.6%	1.6%	4.0%	45.9%	0.3%

Figure 3-2b. Materials of Construction Distribution Mains Totals

The mix of materials for distribution systems is different in different regions of the country and has been gradually changing to predominantly coated and wrapped steel and to polyethylene plastic, as shown in the discussion on infrastructure replacement programs, Section 5.4.10. Figures 3-2c and 3-2d show the mixes of materials for distribution mains and number of service lines, respectively, for the five different NAPSR regions. A map of the NAPSR regions is shown in Figure 3-2e.

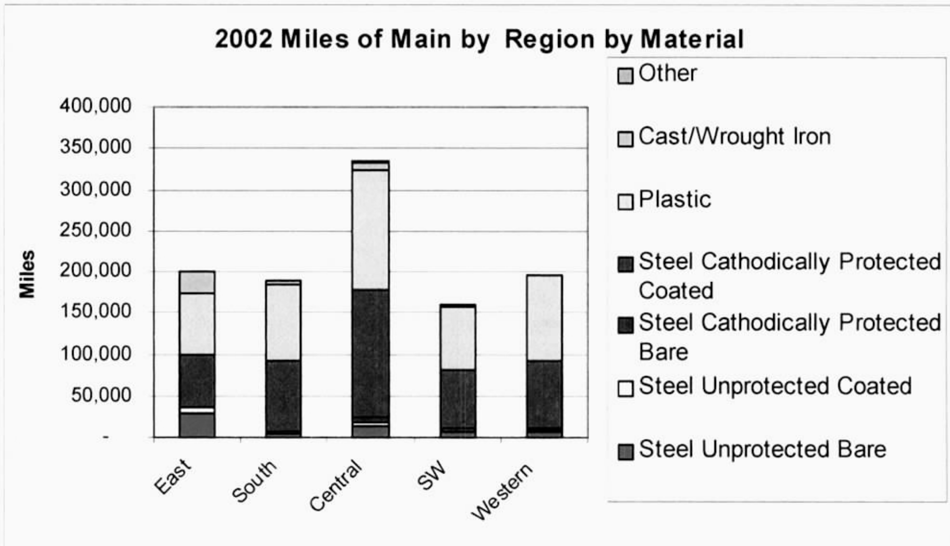


Figure 3-2c. Distribution of Materials of Construction for Mains by NAPSR Region

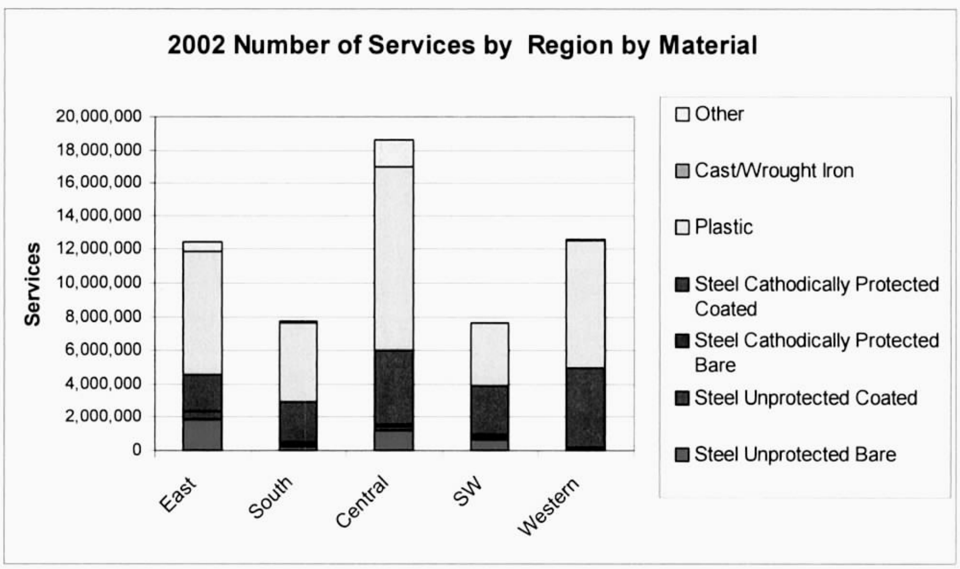


Figure 3-2d. Distribution of Materials of Construction for Service Lines by NAPSR Region

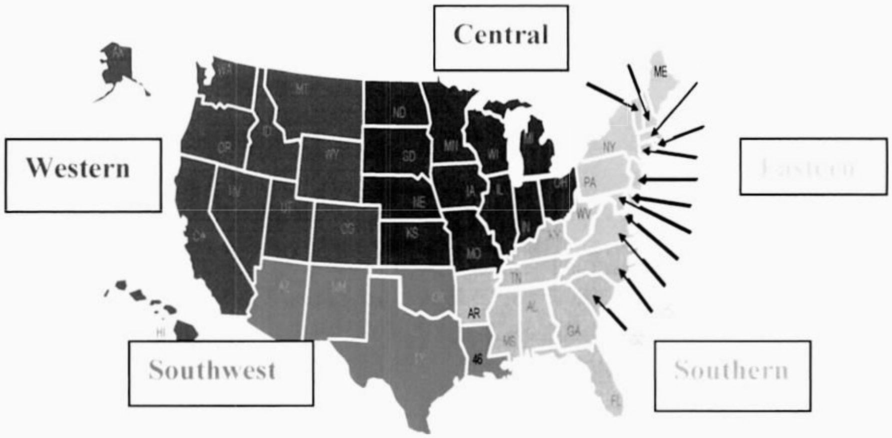


Figure 3-2e. NAPSR Regions

3.2.3 System Pressures

Most transmission pipelines operate at stress levels that exceed 20% of the "specified minimum yield strength" (SMYS) of the line, for metal pipelines. The SMYS depends on the type of metal and is an indicator of when the metal in the pipe starts to yield, deforming in a way that does not return it to its original shape. Also, according to the transmission line definition in 49 CFR Section 192.3 – Definitions, a pipeline operating below 20% SMYS is also classified as a transmission line if it:

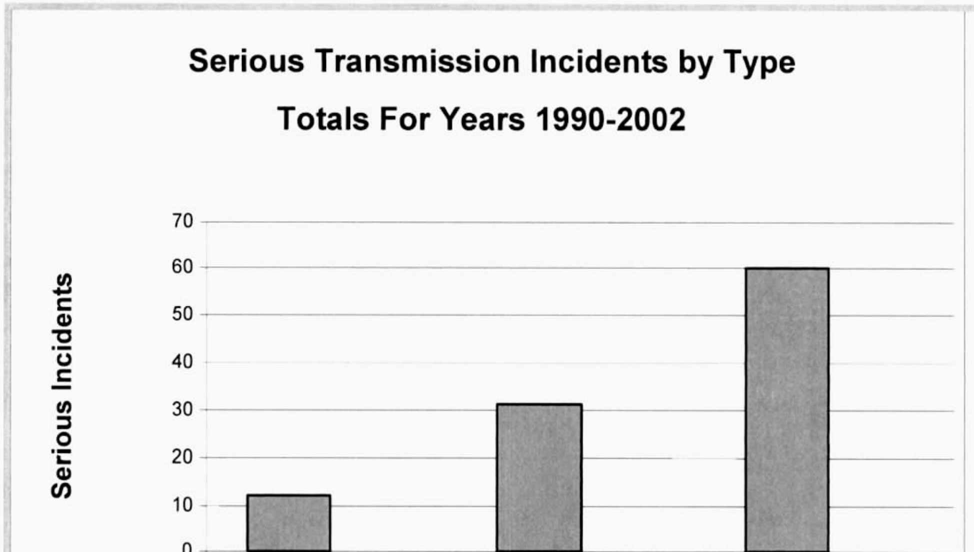
- Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center; or
- Transports gas within a storage field.

Transmission pipelines typically operate at pressure levels between 600 pounds per square inch (psi) and 1200 psi, and in some cases up to 2000 psi. Distribution pipelines typically operate at pressures ranging from 0.25 psi, with gas delivered directly to customers without any additional reduction in pressure, to 60 psi with relatively few distribution pipelines operating at higher pressures (high pressure distribution pipelines) of up to 400 psi. As suggested in subsection 3.2.1, page 3-1, because of the use of pressure districts, in distribution systems, it is common for a distribution network to include multiple sub-systems with a range of pressures.

3.2.4 Typical Failure Mechanism

Pipeline ruptures are more likely in high-pressure (high stress) than in low-pressure (low stress) pipelines. The OPS transmission incident report asks operators to report if the incident resulted in a leak or a rupture, with a rupture being defined as a full failure of the pipe wall. Figure 3-3 shows the breakdown of the 103 reported transmission pipeline incidents involving a fatality or injury (F&I), for the period 1990 through 2002. Ruptures account for almost three times as many Serious Incidents as leaks (31 versus 12).

The most common incident type, however, is the "Other" category (58.3%) where operators did not associate the incident with a leak or a rupture. Further evaluation of this category could not be investigated, as this was the only information, provided by the operator, included in the OPS database.



	Leaks	Ruptures	Other
Incidents	12	31	60
% of Total	11.7%	30.1%	58.3%

Figure 3-3. Serious Incidents by Incident Type

Distribution pipeline incidents typically result in a leak, not a rupture, due to the relatively low operating pressures, and correspondingly lower operating stress in the pipe, in distribution systems. A 2001 study conducted by Battelle Laboratories for the Gas Technology Institute provides further information about the conditions under which ruptures and leaks occur in steel pipelines[1]. The exceptional case for distribution systems is rapid crack propagation in certain types of plastic pipe. This was the subject of a 2000 NTSB report and gave rise to an OPS advisory bulletin and the start of a plastic pipe failure data collection project under the oversight of a government-industry group (see Section 5.4.10).

During the period of the current study (1990-2002), the OPS distribution incident report form did not require operators to report whether the incident resulted in a leak or a rupture. As a result, there are no data for distribution corresponding to the transmission data shown in Figure 3-3. The new Distribution System Incident Report Form, issued in March 2004, requires operators to indicate if an incident resulted in a leak, rupture, or other.

[1] Leis, B. N. et al, *Leak Versus Rupture Considerations for Steel Low-Stress Pipelines*, Topical Report GRI-00.0232, January 2001.

3.2.5 Location of Infrastructure Facilities

Transmission pipelines are predominately located in Class 1 and Class 2 locations, normally on operator owned rights-of way or permanent easements as shown in Figure 3-4. Class locations are defined in 49 CFR Section 192.5 and represent locations of differing population density. Distribution pipelines are predominately located in Class 3 and Class 4 locations. A higher-class location number means a higher population density. For example, a pipeline running through the downtown section of a city is typically in a Class 4 location, and a pipeline running through a residential neighborhood is typically in a Class 3 location.

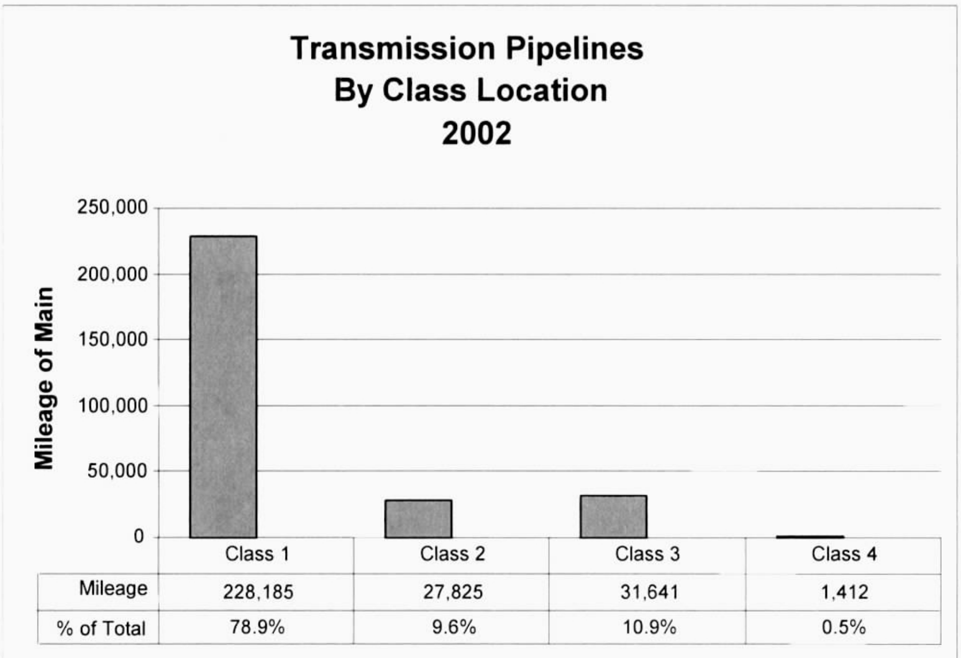


Figure 3-4. Transmission Pipelines by Class Location

Distribution facilities are primarily located in populated areas. Distribution lines do not follow class locations, but the majority of the lines would fall into Class 3 and Class 4 locations under transmission class location definitions. Distribution piping is frequently located in the mostly congested urban areas, typically under pavement in streets, highways and other public right-of-ways or utility easements. This imposes restrictions on the construction and repair of the distribution pipeline, as both natural and man-made underground obstacles unique to an area can be encountered during installation or excavation of the pipe and restricts the use of certain types of assessments.

3.3 Inspection Methods

Both distribution and transmission facilities are subjected to a variety of periodic inspections mandated by 49 CFR Part 192. These include, but are not limited to, the regulations paraphrased in Table 3-1 below.

Table 3-1. Regulation-Mandated Inspection of Gas Pipeline Facilities

Distribution	Transmission
Buried pipeline corrosion protection electrical current readings at test stations spaced along the pipeline must be checked at least once a year	Buried pipeline corrosion protection electrical current readings at test stations spaced along the pipeline must be checked at least once a year
Buried pipeline external corrosion control systems must be checked at least 6 times a year	Buried pipeline external corrosion control systems must be checked at least 6 times a year
Equipment monitoring for internal corrosion at points where the risk of such exists must be checked at least once in 6 months	Equipment monitoring for internal corrosion at points where the risk of such exists must be checked at least once in 6 months
Distribution pipelines exposed to the atmosphere must be checked for external corrosion at least once in every 3 years.	Onshore pipelines exposed to the atmosphere must be checked for external corrosion at least once in every 3 years; offshore pipes exposed to the atmosphere must be checked at least once a year.
Whenever the operator has knowledge that any portion of its buried ferrous distribution pipeline is exposed, the exposed portion must be examined for evidence of external corrosion or if the coating is deteriorated.	Whenever the operator has knowledge that any portion of its buried transmission pipeline is exposed, the exposed portion must be examined for evidence of external corrosion or if the coating is deteriorated.
Operator carries out continuing surveillance of its facilities to determine and take appropriate action concerning changes in population density near the pipeline, failures, leakage history, corrosion and other unusual operating and maintenance conditions.	Operator carries out continuing surveillance of its facilities to determine and take appropriate action concerning changes in population density near the pipeline, failures, leakage history, corrosion and other unusual operating and maintenance conditions.
If a segment of pipe is determined to be in unsatisfactory condition, but no immediate hazard exists, the operator must initiate a program to recondition that segment or phase it out. If this is not possible, the operator must reduce the operating pressure of the pipeline, in accordance with prescribed guidelines. If an immediate hazard exists, the operator must take prompt action to repair the segment.	If a segment of pipe is determined to be in unsatisfactory condition, but no immediate hazard exists, the operator must initiate a program to recondition that segment or phase it out. If this is not possible, the operator must reduce the operating pressure of the pipeline, in accordance with prescribed guidelines. If an immediate hazard exists, the operator must take prompt action to repair the segment.
Distribution pipelines in places or structures where anticipate physical movement or external loading could take place must be patrolled at least 4 times a year in business districts and twice a year outside business districts.	Each operator must patrol its transmission pipeline right-of-way at intervals between 4 times and once a year, depending on certain risk factors.

Table 3.1 (continued)

Distribution pipelines in business districts must be checked for leaks at least once a year including tests for gas presence in subterranean facilities and other areas near a leak.	Transmission pipelines carrying odorized gas must be checked for leaks at least once a year.
Distribution pipelines outside business districts must be checked for leaks at least once every 5 years. Where electrical readings for corrosion protection are impractical, the leak checks must be at least once every 3 years.	Emergency shutdown devices at gas compressor stations must be tested at least once a year.
Disconnected gas service lines must be re-tested before being reconnected.	
Each distribution line valve that may be necessary for the safe operation of the system must be inspected at intervals not exceeding one year.	Each transmission line valve must be inspected and partially operated at least once a year.
Each pressure limiting and pressure regulating station must be inspected and tested at least once a year. This includes inspection of the gas pressure history recorded at these stations.	Each pressure limiting and pressure regulating station on the transmission pipeline must be inspected and tested at least once a year. This includes inspecting the gas pressure history recorded at these stations.
Pressure relief devices must be tested at least once a year for the ability to protect the pipeline from over pressure	Pressure relief devices on the pipeline or at compressor stations to must be tested at least once a year for the ability to protect the pipeline from overpressure.
If larger than 200 cubic feet in size, each underground vault housing pressure regulating or pressure limiting equipment must be tested for gas leaks at least once a year.	If larger than 200 cubic feet in size, each underground vault housing pressure regulating or pressure limiting equipment must be tested for gas leaks at least once a year.
(a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.	After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must contain a natural odorant or be odorized so that a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell unless: (1) At least 50% of the length of the line downstream from that location is in a Class 1 or Class 2 location; (2) The line transports gas to certain facilities; (3) In the case of a lateral line which transports gas to a distribution center, at least 50% of the length of that line is in a Class 1 or Class 2 location; or (4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.
Odorant concentrations must be periodically monitored using test instruments.	Odorant concentrations must be periodically monitored using test instruments.

A comparison of required inspections shows the requirements to be similar for both systems with some exceptions. The odorization requirement, which is not in itself an inspection method, serves as an aid to inspections. The entry in Table 3-1 is based on the requirement as stated in 49 CFR §192.625. It should be noted that some transmission pipelines in urban areas must carry odorized gas. In addition, some states impose additional odorization requirements for transmission pipelines. The scope of this study did not include an investigation of the individual state regulations.

As noted above, distribution pipelines, and transmission pipelines in populated areas, carry odorized gas. Because of the odorant present in the gas, gas customers are more readily aware of the presence of a leak in distribution lines than transmission lines. A study conducted by the Pierce Foundation for the Gas Research Institute in the early 1980s indicated that the odor could be detected by 90% of the population (persons with a normal sense of smell) even when there is a concentration of 0.2 to 0.5 parts of odorant per million parts of air (ppm), which is a relatively low concentration. The range of gas concentrations in air for ignition to occur must be between 4.5 and 15% by volume. This corresponds to a concentration of 45,000 to 150,000 ppm of gas in air. Federal regulations require operators to odorize gas so that it is readily detectible by a person with a normal sense of smell when the gas-air mixture is at one fifth of the lower explosive limit. This is equivalent to approximately 50 ppm of odorant in gas. Thus, people are capable of detecting gas in the air at quantities that are at 1/1000th the concentration of gas than can ignite.

Distribution operators participating in this study verbally reported receiving many customer calls daily, involving the smell of gas and frequent interactions with state pipeline safety personnel having jurisdiction over the operators' system. In many cases, company personnel responses to such calls and even state inspector actions end up in an inspection of the reported area or facility. These inspections and the data gathered are often unique to distribution pipelines. Thus, because of the location of distribution facilities, because all gas is odorized, and because of the many contacts with customers, the public, and state pipeline safety inspectors, gas distribution facilities are subject to much more frequent close inspections than those required by the pipeline safety regulations.

3.4 Connection to Customers

Transmission pipelines normally do not have a direct connection to household end-users. They do have direct connections with large volume customers as defined in 49 CFR Part 192.3. Transmission lines are often "looped", meaning they consist of two or more interconnected parallel pipelines. Absent such connections, taking a transmission pipeline out of service for the purpose of assessment by pressure test or in-line internal inspection will not automatically cause a customer interruption. Under certain demand conditions, looped transmission lines may be able to continue to supply end-users when one or more loops are taken out of service. Interruptions will take place, however, if the transmission pipeline is a single point of supply to a distribution center or a large volume customer and the lines are not looped.

Distribution pipelines are directly connected to end-users. Taking a section of distribution infrastructure out of service for an assessment will result in customer service interruptions, unless the distribution network is configured to allow re-routing around the pipeline that is being assessed.

Only in cases where the number of customers is small can a temporary supply using portable sources provide the gas. In a 2001 internal American Gas Association (AGA) study[1], it was shown that taking a line out of service for assessment could introduce added hazards if temporary supplies are used to feed a large number of customers in a distribution system.

3.5 Customer-Owned Jurisdictional Piping

In distribution systems, customers in some states own jurisdictional facilities. The most common example of this is where the customer meter is located at a building and the customer is responsible for installing and repairing the service line on their property. In this case, the customer owns the service line but the distribution operator is responsible for monitoring and inspecting the customer-owned pipe under state requirements.

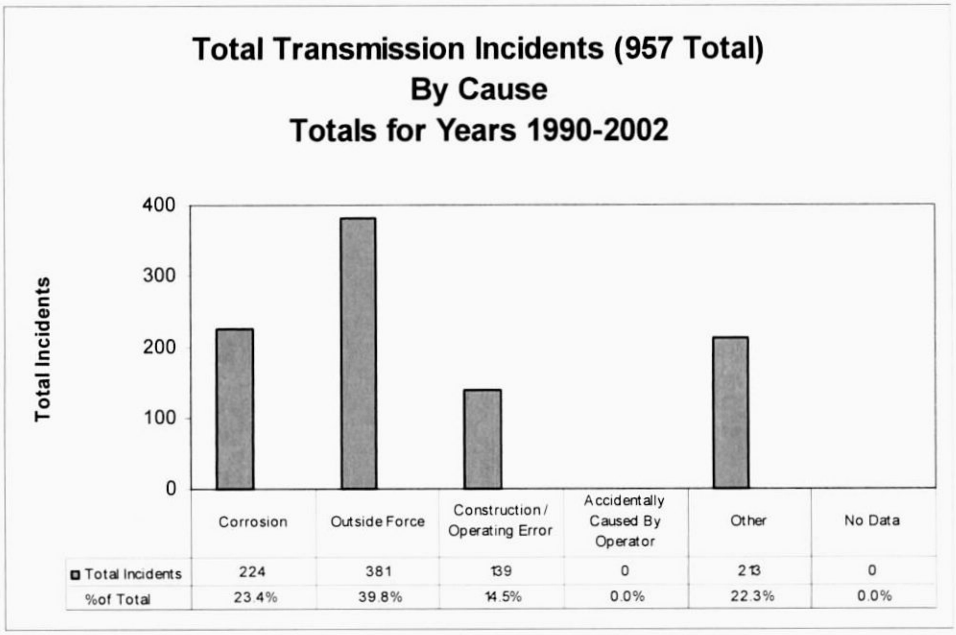
3.6 Incident Review for the Period 1990 – 2002

The following subsections compare incident statistics between Transmission Pipelines and Distribution Systems. The purpose is to determine, at a high level, if there are significant differences in safety performance between Transmission Pipelines and Distribution Systems.

3.6.1 Total Incidents by Cause

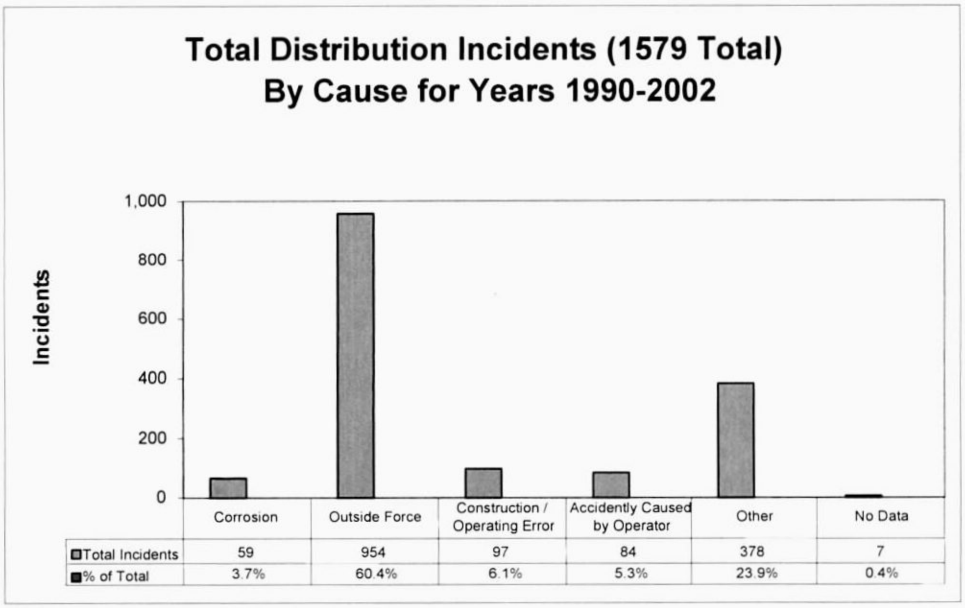
Figures 3-5a and 3-5b show the causes for transmission and distribution incidents reported by operators for the period of 1990 through 2002. During the period, there were a total of 957 transmission pipeline incidents and 1579 distribution incidents (as defined in 49 CFR Section 191.3) reported to the OPS database. Outside force is the predominant cause of incidents for transmission and distribution pipelines but it is more significant in distribution (60.4%) than in transmission (39.8%). Corrosion is a much more significant cause in transmission pipelines (23.4%) than in distribution pipelines (3.7%). The Other category is a significant cause in both transmission (22.3%) and distribution (23.9%) pipelines. Operators select the "Other" category on the OPS incident reporting form if they could not attribute the incident to one of the other four categories. No additional information is available in the OPS database examined by the authors that would allow the analyst to further determine the cause of these "other" incidents. Detailed examination of each individual incident report to further attempt to classify incidents in this category was not within the scope of this study.

[1] Discussion of Feasibility of Temporary Supply of Gas to Customers, G.J. Mosinskis, AGA internal paper, August 3, 2001



	Corrosion	Outside Force	Construction / Operating Error	Accidentally Caused By Operator	Other	No Data
Total Incidents	224	381	139	0	213	0
%of Total	23.4%	39.8%	14.5%	0.0%	22.3%	0.0%

Figure 3-5a. Transmission Total Incidents by Cause



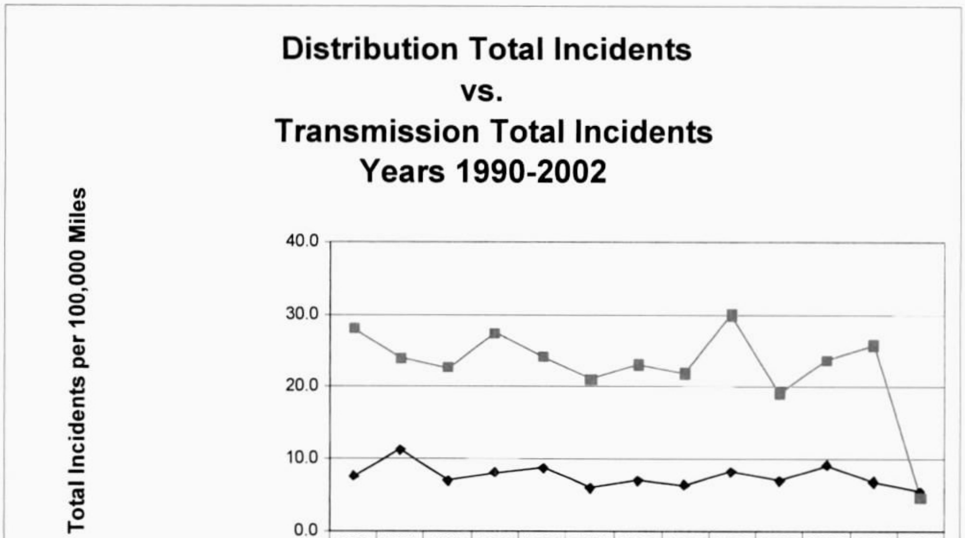
	Corrosion	Outside Force	Construction / Operating Error	Accidently Caused by Operator	Other	No Data
Total Incidents	59	954	97	84	378	7
% of Total	3.7%	60.4%	6.1%	5.3%	23.9%	0.4%

Figure 3-5b. Distribution Total Incidents by Cause

Figure 3-6 displays total incidents normalized by total mileage and reported per 100,000 miles. As in Section 4, distribution mileage used for normalization of both total incidents and total Serious Incidents is the total of mains and service lines mileage.

The normalized incident rate for transmission varied from a high of 29.8 (1998) incidents per 100,000 miles to a low of 4.6 (2002) incidents per 100,000 miles for the 13-year period. Distribution, during the same period, varied from a high of 11.1 (1991) incidents per 100,000 miles to a low of 5.4 (2002) incidents per 100,000 miles. The average of the total incident rate per 100,000 miles per year for the 13-year period is less for distribution (7.4) than for transmission (22.6).

Trend lines for both transmission and distribution total incidents for the 13-year study period were indeterminate at a 90% confidence level based on the Mann-Kendall (MK) statistical test, indicating that an upward or downward trend could not be shown at the 90% confidence level. Refer to Appendix D for a more detailed discussion of the MK statistical analysis technique.

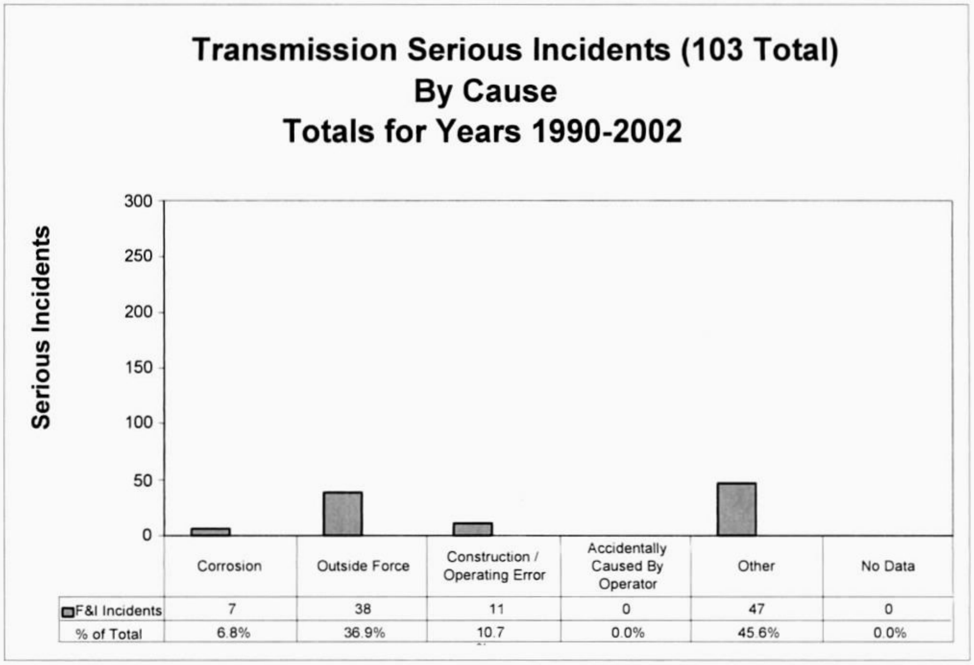


	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Distribution Total Incidents	7.5	11.1	6.9	8.0	8.5	5.9	6.9	6.3	8.2	7.0	9.0	6.8	5.4
Transmission Total Incidents	28.1	23.9	22.5	27.4	24.0	20.7	23.0	21.6	29.8	18.9	23.6	25.6	4.6

Figure 3-6. Normalized Total Incidents (Transmission and Distribution)

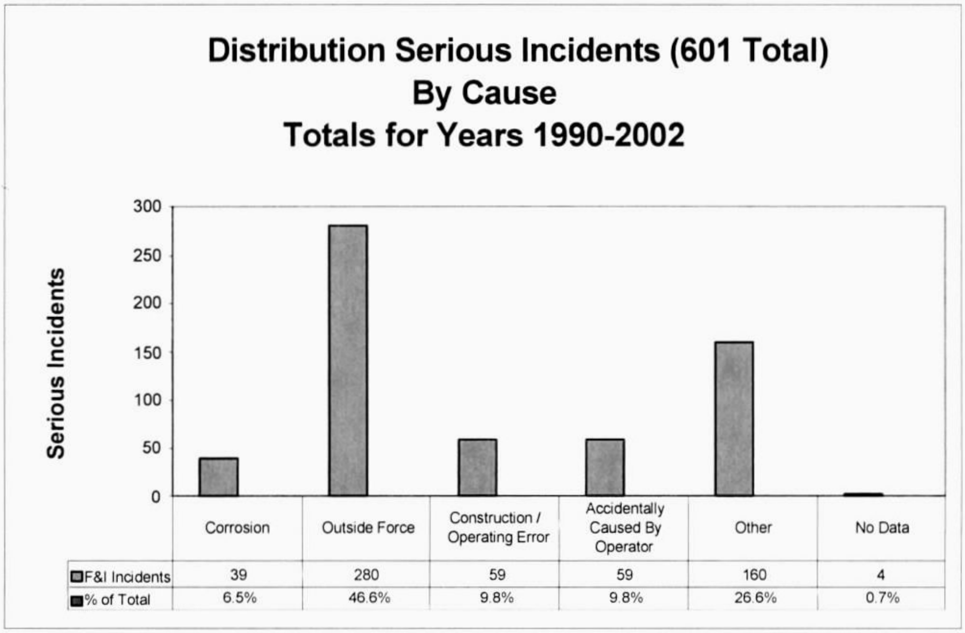
3.6.2 Total Serious Incidents by Cause

Figures 3-7a and 3-7b show the causes for the serious transmission and distribution incidents as reported by operators for the period of 1990 through 2002. During the period, there were 103 serious transmission and 601 serious distribution incidents. As with total incidents, the predominant cause of Serious Incidents reported for distribution pipelines is outside force (46.6%). However, the predominant cause of Serious Incidents on transmission pipelines is "Other" (45.6%) with outside force as the second largest cause (36.9%).



	Corrosion	Outside Force	Construction / Operating Error	Accidentally Caused By Operator	Other	No Data
F&I Incidents	7	38	11	0	47	0
% of Total	6.8%	36.9%	10.7	0.0%	45.6%	0.0%

Figure 3-7a. Transmission Serious Incidents by Cause



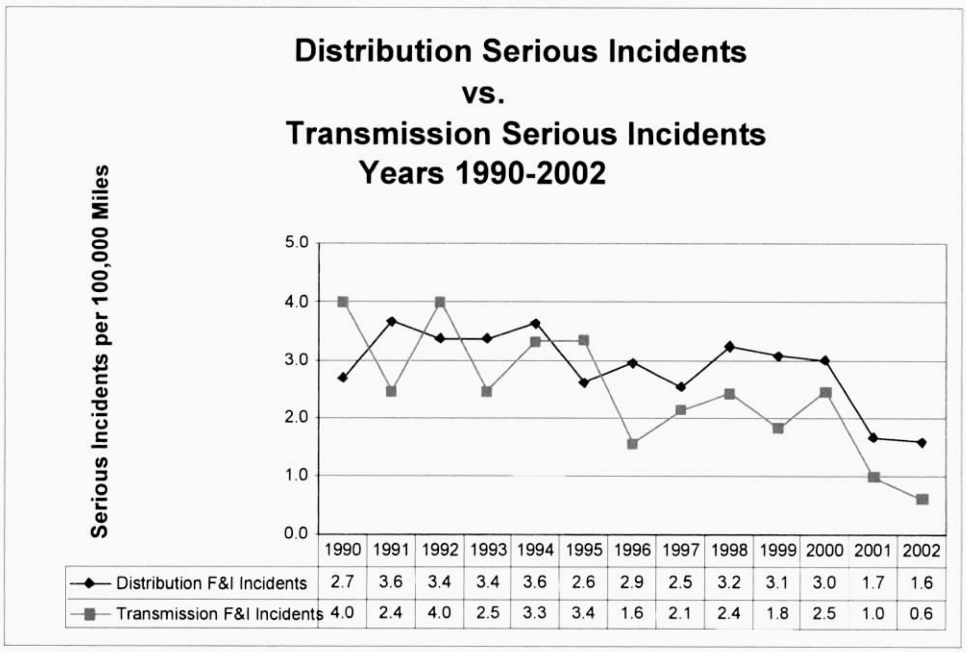
	Corrosion	Outside Force	Construction / Operating Error	Accidentally Caused By Operator	Other	No Data
F&I Incidents	39	280	59	59	160	4
% of Total	6.5%	46.6%	9.8%	9.8%	26.6%	0.7%

Figure 3-7b. Distribution Serious Incidents by Cause

Given that the mileages of distribution and transmission are different, the data were normalized by the mileage of each sector to provide a more meaningful comparison of statistics for these two sectors. Figures 3-8a and 3-8b display total Serious Incidents normalized to show the incidents per 100,000 per year.

The normalized incident rate for transmission varied from a high of 4.0 (1990 and 1992) incidents per 100,000 miles of transmission pipeline to a low of 0.6 (2002) incidents per 100,000 of transmission miles for the 13-year period. Distribution, during the same period, varied from a high of 3.6 (1994) incidents per 100,000 miles of distribution pipeline to a low of 1.6 (2002) incidents per 100,000 miles of distribution pipeline. The average of the total Serious Incidents per 100,000 miles per year for the 13-year period is 2.4 for Transmission Pipelines and 2.8 for Distribution Systems.

Trends for both transmission and distribution incident rate resulting in fatalities and injuries for the 13-year period were downward at a 95% confidence level based on the MK test. During the period, the trend line shows a decrease of about 41% in distribution (3.64 in 1990 to 2.13 in 2002) and about 73% in transmission (4.17 in 1990 to 1.12 in 2002).



	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Distribution F&I Incidents	2.7	3.6	3.4	3.4	3.6	2.6	2.9	2.5	3.2	3.1	3.0	1.7	1.6
Transmission F&I Incidents	4.0	2.4	4.0	2.5	3.3	3.4	1.6	2.1	2.4	1.8	2.5	1.0	0.6

Figure 3-8a. Normalized Serious Incidents (Transmission and Distribution)

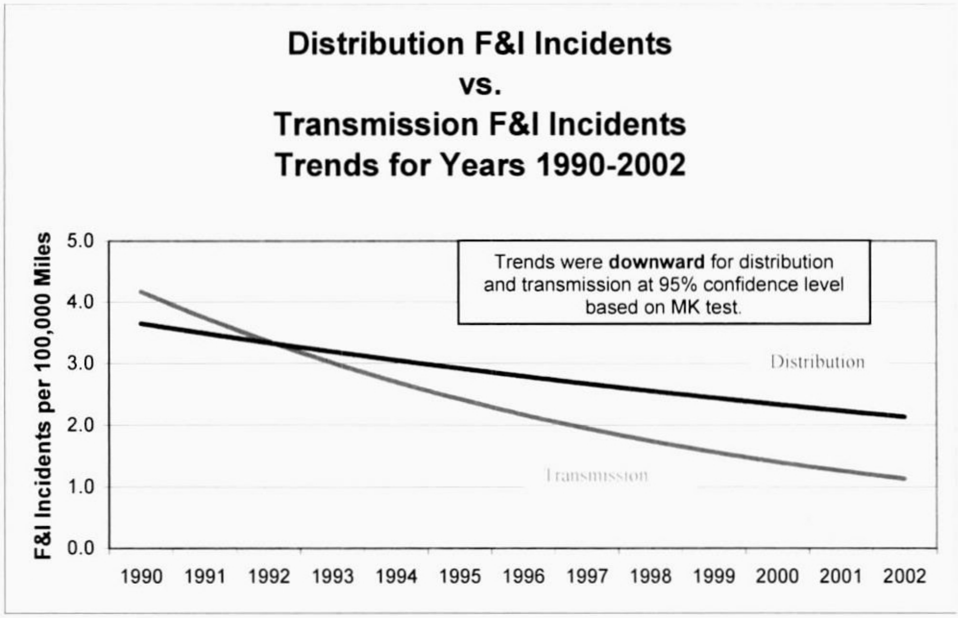


Figure 3-8b. Trend Lines for Serious Incidents

3.6.3 Fatalities and Injuries

During the study period, 179 fatalities and injuries occurred because of an incident on Transmission Pipelines. During the same period, 1,088 fatalities and injuries occurred because of an incident on Distribution Systems.

When normalized, this translates to an average of 4.7 fatalities or injuries per year per 100,000 miles of distribution and 4.6 fatalities or injuries per year per 100,000 miles of transmission over the study period.

These relate to 1.7 (179/103) fatalities or injuries per Serious Incidents for Transmission Pipelines and 1.8 (1,088/601) fatalities or injuries per Serious Incidents for Distribution Systems.

3.7 Summary

On a normalized basis, the differences between distribution and transmission incident statistics are small, both in terms of Serious Incidents and in terms of fatality and injury counts. However, key differences exist between transmission and distribution pipeline systems in the following areas:

- type of infrastructure;
- size of pipelines;
- system operating pressures;
- mix and types of materials of construction;
- typical failure mechanisms;
- inspection methods and inspection frequencies;
- gas odorization;
- location of facilities; and
- connection to customers.

4.0 REVIEW OF DISTRIBUTION SAFETY RECORD

4.1 Overview and Approach

The goal of pipeline safety for the distribution infrastructure in this country is continuous improvement with the ultimate objective of no fatalities and injuries associated with distribution systems. Achieving this goal requires monitoring safety performance through appropriate performance measures. One of these performance measures is the incident history over time. The numbers of incidents per year, the number of incidents per 100,000 miles of distribution system, and the corresponding numbers of fatalities and injuries are measures of progress. Safety performance of the distribution system infrastructure is examined in terms of numbers and frequency of reportable incidents under the requirements of 49 CFR Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards. This section examines fatality and injury incidents and fatality and injury counts from January 1, 1990 through December 31, 2002 based on reportable incident data in the OPS, Gas Distribution Incident Data database (mid-1984 – present). These data are available directly from the OPS website at http://ops.dot.gov. Pipeline statistics can be found in the top menu bar. These data are the foundation of this study, just as they have been used in other past studies.

A fundamental difference between this and earlier studies is the manner in which the data were sorted and analysed, and in the application of a standard statistical test to determine whether data trends exist within specified confidence limits.

The overall approach was to propose various analyses to a team comprised of representatives from the industry and governmental regulatory community and, with their input, to select a number of analyses that by consensus were of critical interest to the team. The data were then sorted and analysed, to provide information on the incidents by part of the distribution infrastructure, materials of construction, and the causes of incidents, as classified in the OPS database. Data were normalized on a 100,000-mile basis by type of material or portion of the system to prevent distortions from changes in the mileage of mains and service lines over time and of their corresponding different materials of construction for the pipe.

4.2 Previous Studies

Over the years, a number of studies have been done which have examined the incident data for the distribution infrastructure. Some of the more prominent studies are discussed in the Technical Note of Appendix A. The overriding conclusion of these studies was that the primary cause of distribution incidents is outside forces and especially third party damage. These studies also illustrated the differences in the proportion of incidents that occurred in the major parts of the distribution infrastructure: mains, service lines, meter set assemblies and other parts, as defined by the OPS database. These earlier studies provided a launch pad for the current study, which expanded the analysis of the OPS data and examined the data in new ways.

4.3 Current Analysis

4.3.1 Background and Purpose

Initial work in this study examined the reportable incident data from the OPS database for the period 1985 through 2002. The results were documented in the Technical Note in Appendix A. Various sorts and compilations of the data were made to shed light on the characteristics of the distribution infrastructure relative to incidents, with the intent of clearly identifying and providing a basis for setting priorities for any future industry actions in any "problem" areas. The overall goal is to enhance distribution infrastructure safety by focusing resources where they will achieve the most good.

The data suggested that there had been a dramatic change in incident rates over the study period, but there were some characteristics of the data that were troubling. The initial numbers of incidents and incident rates per mile or mile-year seemed extremely high relative to later years. While this at first seemed to be an indication of a sharp decline in incident rates over time, it was also recognized that this could be due to other factors. In 1985, one of the reporting criteria for property damage changed from $5,000 to $50,000. Combined with the other criteria (incidents involving a fatality or injury that requires hospitalization, or incidents the operator deemed significant), inconsistencies can arise from year to year in the incidents reported to the database. There are no standard criteria for estimating the costs of property damage, and the discretionary reporting of significant incidents based on the operators' judgment of the importance of the incident can lead to variations in what would be reported. Furthermore, monetary inflation over time will change the severity of the incidents that would be reported under the $50,000 value criterion.

Given these factors and the fact that the primary concern for safety performance is harm to persons, that is, fatalities and injuries (F&I), it was decided to use a subset of the total incident database that focused on incidents with fatalities and injuries only, herein also referred to as "Serious Incidents". This eliminated any biases related to varying property damage criteria, inflationary effects and reduced the biases due to the discretionary reporting of incidents the operator deemed to be reportable based on the discretionary criterion. The fundamental approach adopted in this report is the analysis of Serious Incidents to characterize the safety performance of the distribution infrastructure. The incidents subject to analysis for the distribution infrastructure were thus reduced from the total of 1,579 for the period 1990-2002, to 601 Serious Incidents.

For the remainder of the report, the term incidents refers to Serious Incidents, that is, those incidents that have resulted in a fatality or injury requiring hospitalization.

Figure 4-1 shows a time series for the total number of Serious Incidents, by year, over the study period.

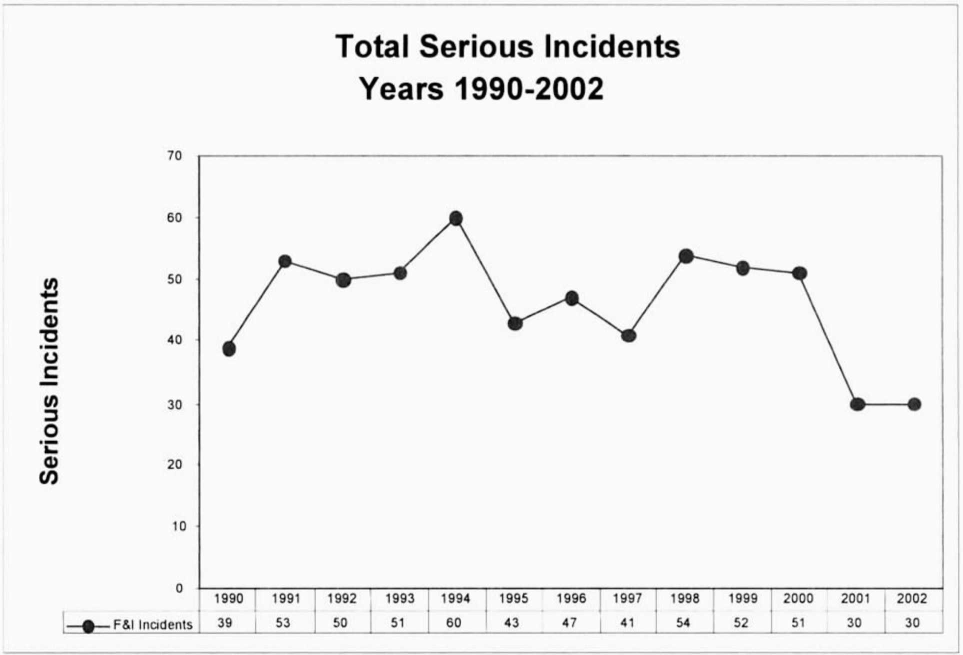


Figure 4-1. Serious Incidents by Year over the Study Period Time Series

4.3.2 Serious Incident Causes

The OPS database classifies causes into the following major categories:

- Corrosion;
- Outside forces;
- Construction operating error;
- Accidentally caused by operator; and
- Other.

Each of these categories is explained in detail in the DOT Instructions for RSPA Form 7100.1 (3-84) given in Appendix H.

This initial cut was used in the data analysis of Serious Incidents. The data were further analysed to determine the dominant cause of the Serious Incidents within the five categories, the part of the system where the incident occurred, and the materials of construction that failed.

Figure 4-2 shows the apportionment of incidents by cause category. Outside force is the dominant cause of Serious Incidents (46.6%), followed by the category labelled "Other" (26.6%). Sufficient detail does not exist in the OPS incident database to further define the incidents in the "Other" cause category. However a review of additionally available information on each specific incident shows that many incidents in this category involved customer piping or appliances that are not jurisdictional to OPS or operated and maintained by the distribution operator. At the time of preparation of this report, the data available at OPS in this category were being further analysed by the Allegro Energy Group under a separate effort sponsored by

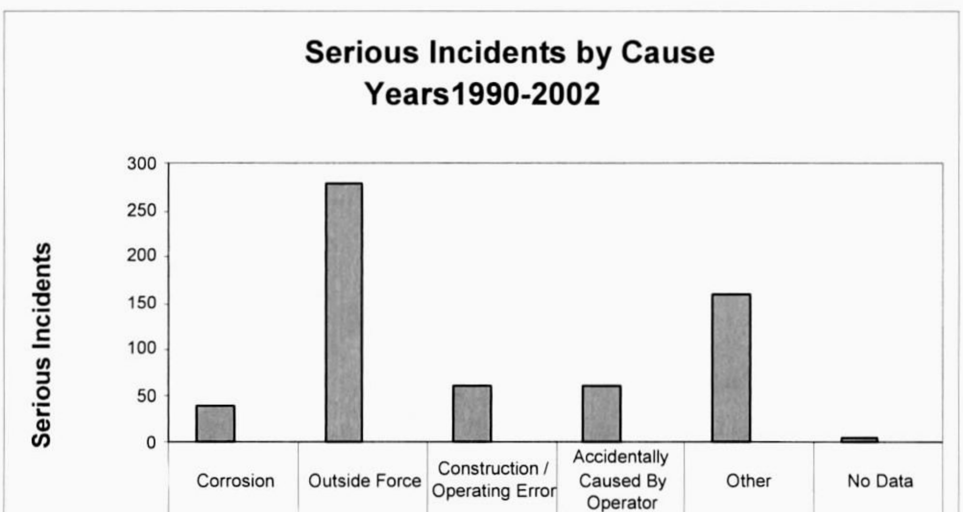
OPS[1]. Corrosion (external and internal) is a relatively small contributor to Serious Incidents for distribution systems (6.5%).

Outside forces comprise several specific types of forces:

- First or second party damage (operator or his/her agent, respectively);
- Third party damage;
- Earth movement, (e.g. landslide/washout, subsidence, frost heave, earthquakes, etc);
- Lightning or fire; and
- Other.

Of these, most outside force incidents (74.3%) result from third party damage. This subcomponent represents 34.6% of the total number of Serious Incidents. In addition, most outside force and third party damage Serious Incidents occur on mains as shown in Appendix B.

Further analyses, as shown in Appendix B, reveal that the percentage of Serious Incidents in each category varies with the part of the system and by material of construction.



	Corrosion	Outside Force	Construction / Operating Error	Accidentally Caused By Operator	Other	No Data
Incidents	39	280	59	59	160	4
% of Total	6.5%	46.6%	9.8%	9.8%	26.6%	0.7%

Figure 4-2. Incidents by Cause Category

On a macro scale, excluding the "Other" and "No Data" categories, there are 437 Serious Incidents shown in Figure 4-2.

[1] Cheryl Trench of the Allegro Energy Group presented preliminary information at the December 16, 2005 DOT public meeting on Distribution Integrity. Refer to OPS website at http://ops.dot.gov

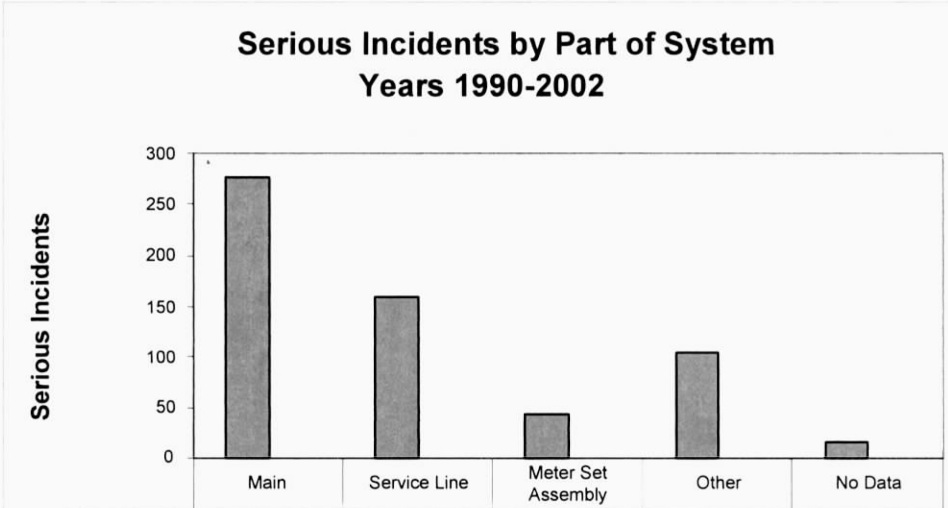
Consider first the primary component of "Outside Force" (namely, from Figure B38H, Appendix B, 208 Serious Incidents due to third party damage), and "Construction/Operating Error" (namely 59 Serious Incidents involving poor workmanship during construction, error in operating procedure application, or physical damage during construction). One can ascribe these to primarily behavior-based conditions, where operator actions on physical facilities, within bounds affordable to the customers, are limited in their ability to influence the behavior of a human or humans affecting the course of events leading to such incidents. Most of the remaining incident causes, primarily "Corrosion" and "Accidentally Caused By Operator," can be classified as system-based conditions, where operator actions on physical facilities are able to affect the facilities, or where operator actions can more strongly influence their own procedures or the behavior of their own employees in order to avoid or mitigate events leading to a possible incident.

This distinction indicates that roughly over 60% of the Serious Incidents (excluding "Other" and "No Data" categories) are related to behavior-based conditions. The main reason for this distinction is because preventing behavior-based conditions leading to incidents calls for approaches that are very different from those used for preventing system-based conditions leading to incidents. The former emphasizes affecting behavior or actions of people, while the latter emphasizes physical measures applied to the operator's jurisdictional facilities or procedures.

Serious Incidents by Part of System

Figure 4-3 shows the apportionment of incidents by part of the system. Most of the Serious Incidents are associated with the mains, followed by services, meter set assemblies and a category termed "Other" and "No data." While it would make sense to normalize these by the appropriate miles for comparison purposes, there is no mileage associated with the last two categories. Therefore, absolute incident numbers are presented here.

The mains, service lines and meter set assemblies account for the jurisdictional assets of the pipeline system. Sufficient details do not exist in the OPS incident database examined by the authors of this report but, as discussed earlier in this section, available detailed information at DOT shows that the "Other" category contains incidents not associated with these parts of the system. They typically include pipe and appliances down stream of the meter set assembly where jurisdictional assets are not involved, but which were reported because they fall under the operator's discretionary reporting of "significant" incidents. The "No Data" subset reflects incidents reported for which an operator did not report the part of the system.



	Main	Service Line	Meter Set Assembly	Other	No Data
F&I Incidents	276	161	43	105	16
% of Total	45.9%	26.8%	7.2%	17.5%	2.7%

Figure 4-3. Incidents by Part of the System

Serious Incidents by Material of Construction

The incident causes also vary with material of construction. Corrosion is an issue with steel systems[2], less so with cast iron and not at all with polyethylene. Third party damage is the dominant outside force category with all materials, but cast iron is subject to a higher proportion of incidents from earth movement, which comprises subsidence, landslides, frost heave, earthquakes, and other designations in the OPS database.

Figure 4-4 shows the apportionment of Serious Incidents by material of construction, as an example, for mains.

[2] Because of time and scope limitations, the incident analysis in this report did not attempt to separately analyze incidents for each of the four types of installed steel pipe, namely bare, cathodically protected, unprotected, and coated steel protected and unprotected.

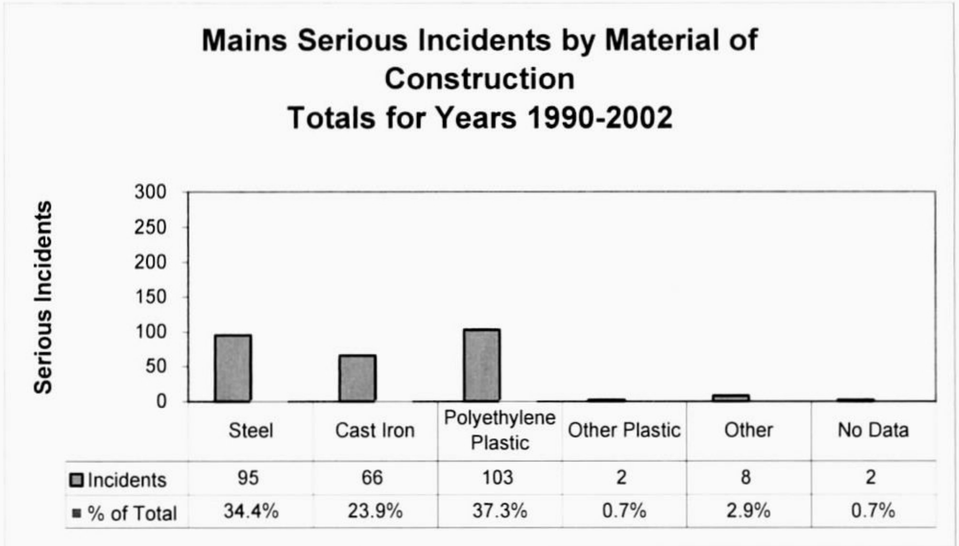


Figure 4-4. Mains Serious Incidents by Material of Construction

This figure shows that most of the incidents on mains involve steel and polyethylene plastic pipe. These materials also comprise most of distribution system mileage. The respective percentages for these two materials are of the same order of magnitude. For mains, cast iron is the third most common pipe material, but is virtually absent for services (less than 0.1%). To obtain valid statistics for comparison of one material against another, it is necessary to normalize the data by the appropriate mileage for each individual material of construction. Details regarding such comparisons can be found in Appendix B.

Mileage Normalized Serious Incident Data

The mileage of the distribution infrastructure can vary from year to year because of changes in the mileage of both mains and service lines, and of individual materials of construction. To provide a consistent basis for system performance comparisons from year to year, the Serious Incident data are normalized for further analysis by 100,000 miles of total distribution piping, mains, or services, and mileage for specific materials of construction, according the data set being analysed.

Figure 4-5 shows the total Serious Incidents data set normalized by total miles of the distribution infrastructure.

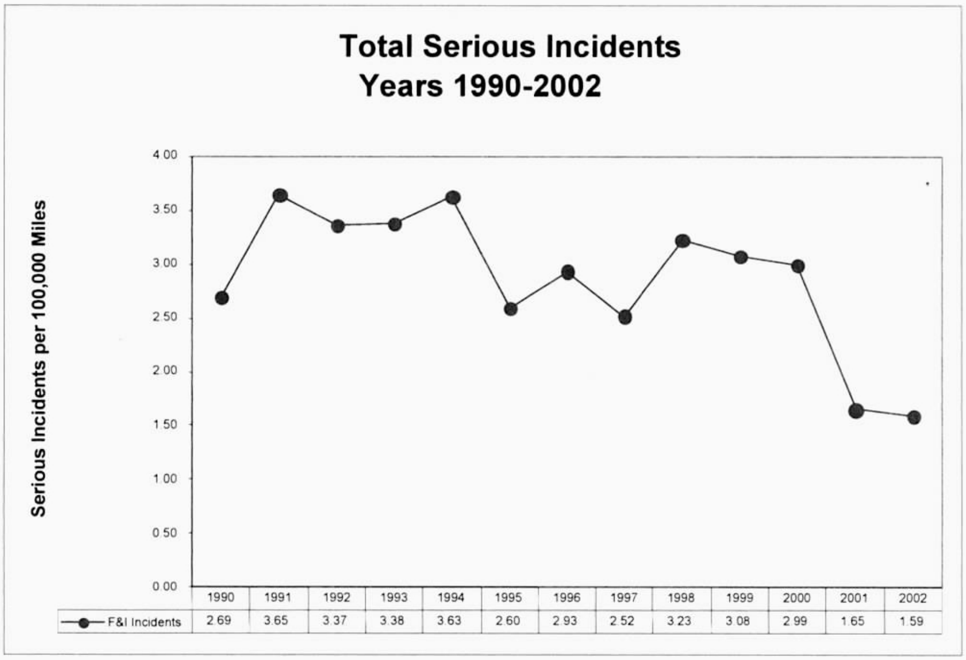


Figure 4-5. Total Serious Incidents by Total Miles of the Distribution Infrastructure

4.3.3 Serious Incident Time Series Analysis

As seen in the preceding figure, the number of Serious Incidents or incidents per 100,000 miles varies from year-to-year, creating a data time series. Appendix B identifies other analyses performed on the data for the various system variables also show similar patterns. Of interest is whether there are any long-term trends to these data. Figure 4-5 appears to indicate a downward trend. To improve the analysis for this report, a formal statistical analysis was conducted to determine if apparent trends over the study period could be supported. The Mann-Kendall (MK) statistical test was applied to determine whether there are, in fact, trends in the various data sets. The MK test was applied to the data at 90% and 95% confidence levels. Details of the MK method are presented in Appendix D.

Table 4-1 denotes by an "X" the Serious Incident data sets where the MK test results indicated a trend. The MK tests for Serious Incidents identified several trends in both the 90% and 95% confidence limit categories. All the figures and more details of the incident analyses are presented in Appendix B. A similar analysis was conducted for fatality and injury counts and the details are presented in Appendix C.

The MK tests indicated there were no upward trends but there were several downward trends (these are discussed later in the report). Indeterminate trends were established for the other data sets listed in Table 4-2. According to the MK test, a flat trend, as represented by unchanging y-values on an x-y plot, would also be considered indeterminate.

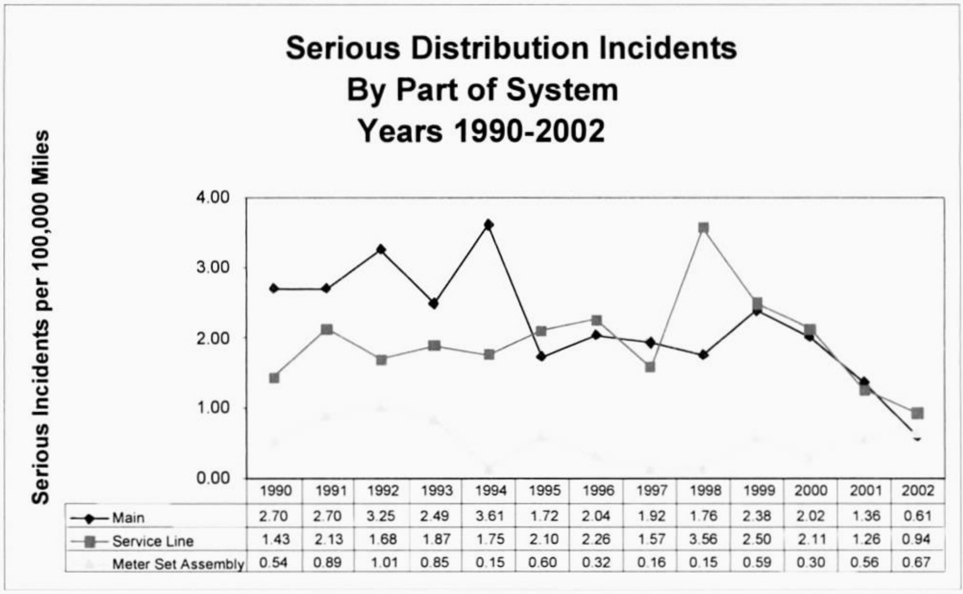
Table 4-1. Serious Incident Data Sets with Established Trends by the MK Statistical Test

Data Set	Confidence 90%	Confidence 95%
Components of the Distribution System (Serious Incidents Only)		
Total Distribution System		X
Mains		X
Corrosion for Mains	X	
Third Party Damage for Mains	X	
Outside Force for Mains		X
Polyethylene Mains		X
Steel Mains		X
All Parts of Distribution System (Serious Incidents Only)		
Outside Force		X
Construction/Operating Error		X
Accidentally Caused by Operator	X	
Corrosion	X	

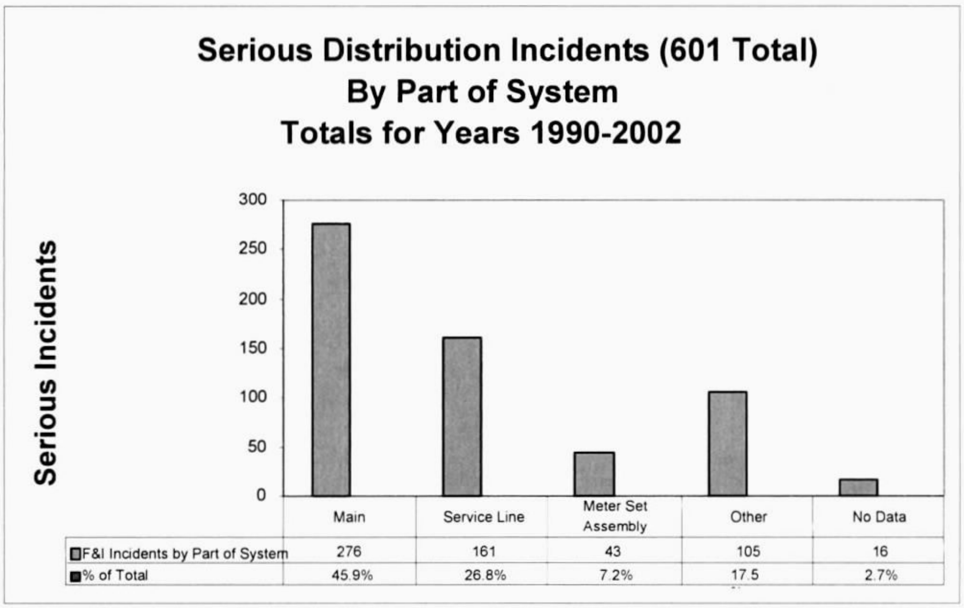
Table 4-2. Serious Incident Data Sets with Indeterminate Trends by the MK Statistical Test

Components of the Distribution System (Serious Incidents Only)
Meter Assemblies
Service Lines
Cast Iron Mains
Polyethylene Plastic Service Lines
Steel Service Lines
Corrosion for Service Lines
Outside Force for Meter Set Assemblies
Outside Force for Service Lines
Outside Force for Steel Service Lines
Outside Force for Polyethylene Plastic Service Lines
Outside Force for Cast Iron Mains
Outside Force for Polyethylene Plastic Mains
Outside Force for Steel Mains
Third Party Damage for Mains
Third Party Damage for Cast Iron Mains
Third Party Damage for Polyethylene Plastic Mains
Third Party Damage for Steel Mains
Earth Movement for Cast Iron Mains
Third Party Damage for Polyethylene Plastic Service Lines
Third Party Damage for Steel Service Lines
Third Party Damage for Service Lines
Polyethylene Plastic Mains, Outside Force-third party
Steel Mains, Outside Force-third party
Service Lines, Outside Force-third party
Steel Service Lines, Outside Force-third party
All Parts of Distribution System (Serious Incidents Only)
Other Causes
Third Party Damage

An example of an analysis for a data set involving time series, addressed for Serious Incidents in Appendix B (and similarly for Fatalities and Injuries in Appendix C), is shown in Figures 4-6a and 4-6b below. The normalizing parameter for each data point is the corresponding mileage for that part of the system except for meter set assemblies. Meter set assemblies incident data are normalized by the number of miles of service line.



	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Main	2.70	2.70	3.25	2.49	3.61	1.72	2.04	1.92	1.76	2.38	2.02	1.36	0.61
Service Line	1.43	2.13	1.68	1.87	1.75	2.10	2.26	1.57	3.56	2.50	2.11	1.26	0.94
Meter Set Assembly	0.54	0.89	1.01	0.85	0.15	0.60	0.32	0.16	0.15	0.59	0.30	0.56	0.67



	Main	Service Line	Meter Set Assembly	Other	No Data
F&I Incidents by Part of System	276	161	43	105	16
% of Total	45.9%	26.8%	7.2%	17.5	2.7%

Figure 4-6a. Example Line Chart and Bar Chart

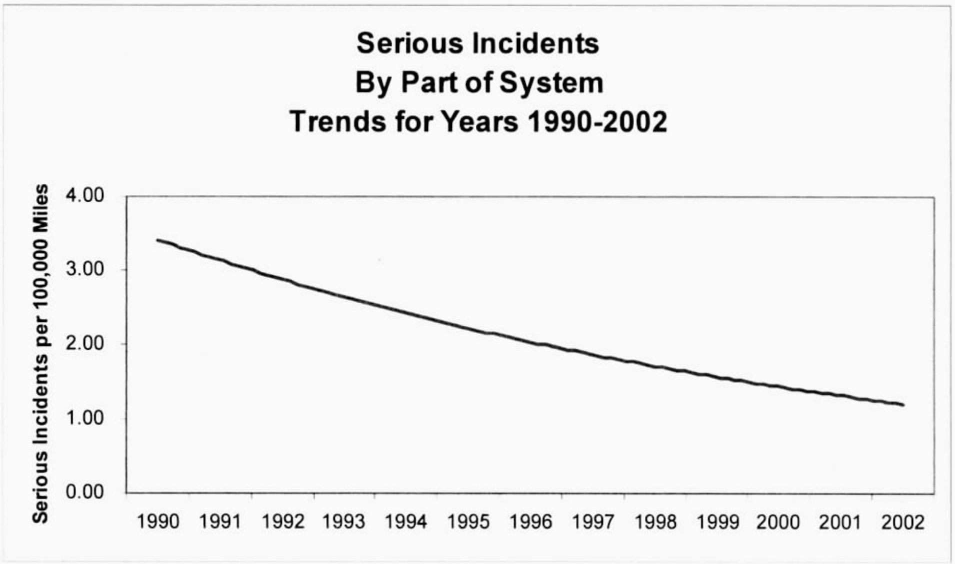


Figure 4-6b. Example Trend Graphs

The service lines and meter set assemblies trends were indeterminate at 90% and 95% confidence level and therefore not shown on the graph. The mains trend, displayed on the above graph, was downward at a 95% confidence level.

4.3.4 Distribution Mains

Figure 4-6b shows the overall results for Serious Incidents associated with mains for the study period. The results show a downward trend in incidents per 100,000 miles at a 95% confidence level.

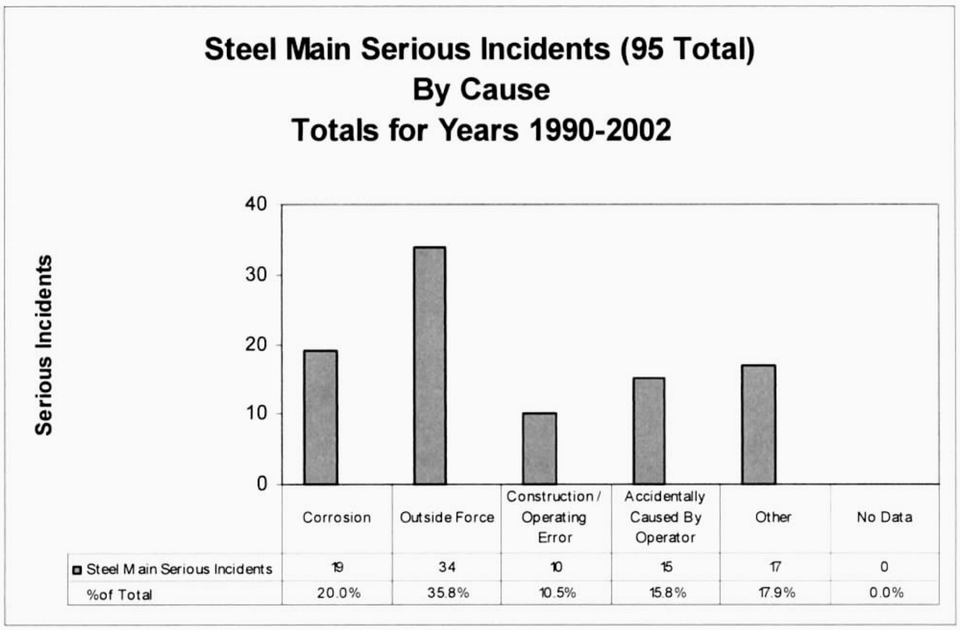
Incident Causes for Mains

The Serious Incident causes on distribution mains vary with material of construction. The principal materials of construction for mains are steel, polyethylene plastic, and cast iron. Other materials make up such a small percentage of the piping that they are virtually negligible for purposes of this study.

Further analysis of the data on steel, polyethylene and cast iron mains on Figures B8, B10, and B9, respectively, in Appendix B show outside force to be the single largest cause of the incidents, accounting for 36% of all Serious Incidents for steel mains, 55% for cast iron, and 52% for polyethylene.

As shown by Figures B38D and B38E in Appendix B, third party damage comprises most of the outside force incidents, with 80% of the incidents for steel and 89% of the incidents on polyethylene piping. Cast iron is subject to a higher proportion of incidents from earth movement, with 75% of all outside force Serious Incidents attributed to earth movement, as shown in figure B-38C in Appendix B. Earth movement is comprised of subsidence, frost heave, earthquakes, and other designations in the OPS database.

For steel mains, as shown in Figure 4-7, causes other than outside force also contributed significantly to the incident counts, contributing 47 percentage points, if the "Other" category is excluded. However, this must be considered in the context of the overall number of Serious Incidents. As shown in Figure 4-4, steel mains contributed 95 incidents to the total of 601 Serious Incidents. This represents 16% of the total.



	Corrosion	Outside Force	Construction / Operating Error	Accidentally Caused By Operator	Other	No Data
Steel Main Serious Incidents	19	34	10	15	17	0
%of Total	20.0%	35.8%	10.5%	15.8%	17.9%	0.0%

Figure 4-7. Steel Main Serious Incidents by Cause Category

Findings

The overall conclusion for mains is that there is a downward trend in Serious Incidents per 100,000 miles of pipe, over the study period. The downward trend is driven by the downward trend for steel and for polyethylene plastic mains, the primary materials of construction for distribution pipeline today.

It should be noted that incidents in the "Other" category represented significant percentages of the total Serious Incidents for mains, namely, 17% for steel, 33% for cast iron, and 8% for polyethylene main. As previously mentioned, the OPS database does not contain sufficient details on these incidents to allow further classification.

4.3.5 Distribution Service Lines

Unlike distribution mains, Serious Incidents show no trend by the MK test for the study period as shown in Figure 4-6b.

Incident Causes for Services

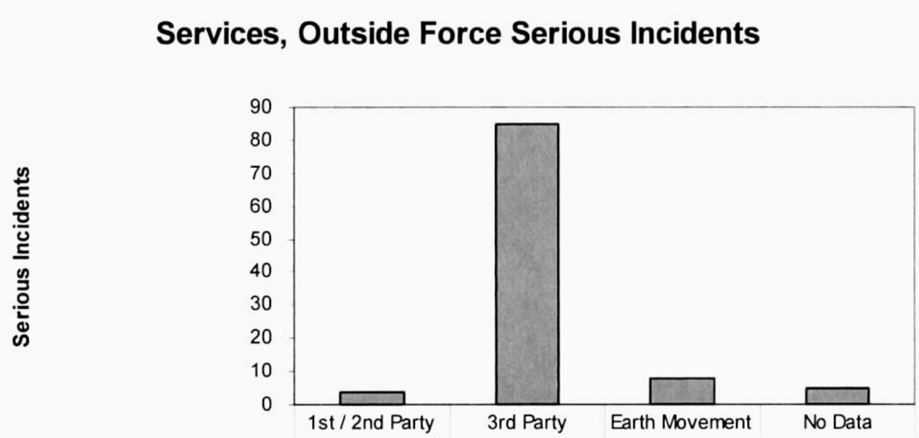
The Serious Incident causes on distribution service lines vary with material of construction. The principal materials of construction for service lines are steel and polyethylene plastic. Other materials make up such a small percentage of the piping that they are virtually negligible for purposes of this study.

Further analysis of the data on steel and polyethylene service lines on Figures B12 and B13, respectively, in Appendix B show outside force to be the single largest cause of the incidents, accounting for 54% of all Serious Incidents for steel service lines and 76% for polyethylene service lines.

As shown in Figure 4-8, third party damage is the dominant outside force category for service lines. This holds true for both steel and polyethylene material of construction as shown by Figures B38G and B38I in Appendix B, with 84% of the outside force incidents for steel and 87% of the outside force incidents on polyethylene piping attributed to the third part damage.

Findings

For service lines, there is an indeterminate trend in Serious Incidents per 100,000 miles of pipe, over the study period. Third party damage is the predominant cause of incidents for both steel and polyethylene plastic service lines.



	1st / 2nd Party	3rd Party	Earth Movement	No Data
Services, Outside Force Serious Incidents	4	85	8	5

Figure 4-8. Outside Force Serious Incidents for Service Lines

4.3.6 Meter Set Assemblies

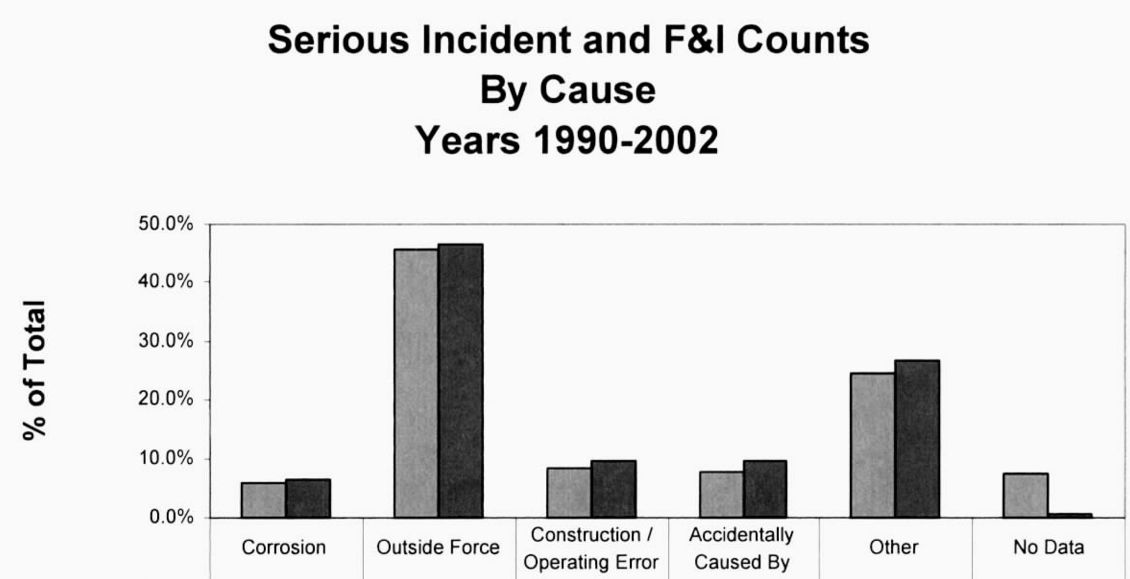
Figures 4-6a and 4-6b also show the overall results for Serious Incidents associated with meter set assemblies for the study period. At study confidence levels of 90% and 95%, the trend was indeterminate. Further analysis of the meter set assemblies data, as discussed in Appendix B, shows that the dominant causes of failure for meter set assemblies are outside forces and other, with third party damage comprising most of the outside forces. No corrosion related Serious Incidents were reported for meter set assemblies during the 13-year study period.

4.3.7 Other and No Data

This category of incidents contains incident reports for which the operator identified the part of the system as other than mains, services, or meter set assemblies. It also includes incident reports for which the operator did not provide any data on the part of the system involved. These incident data were not analysed further in this report because they are not primarily associated with mains, service lines, or meter set assemblies, the major jurisdictional components of the distribution infrastructure.

4.3.8 Consequences

The preceding analyses focused on Serious Incidents. The consequences of these incidents are the fatalities and injuries (F&I). F&I counts were also examined. Over the study period, there was an average of 1.8 per serious incident (i.e., 1,088 F&I for 601 Serious Incidents). F&I counts were analysed in the same manner as the serious incident data, discussed in the preceding sections of this report. They were found to closely mimic the corresponding serious incident data as shown in Figure 4-9 where Serious Incident F&I counts and incidents are examined by cause category.



	Corrosion	Outside Force	Construction / Operating Error	Accidentally Caused By	Other	No Data
F&I Counts	6.1%	45.7%	8.5%	7.8%	24.4%	7.4%
F&I Incidents	6.5%	46.6%	9.8%	9.8%	26.6%	0.7%

Figure 4-9. Serious Incidents and F&I Counts by Cause Category

One exception is the "No Data" cause category. For Serious Incidents the "No Data" category represented 0.7% of the total 601 F&I incidents; however, for F&I counts, Figure 4-9 shows that the "No Data" category accounts for 7.4% of the 1,088 total F&I's. This difference is the result of a single "No Data" incident that occurred in 1996 in which there were 75 total injuries and fatalities.

Details of the analyses performed on the fatality and injury count data sets are presented in Appendix C.

F&I Count Trends

As with the Serious Incident time series, the MK test was applied to a number of the F&I count data sets. The MK tests for total F&I each year (F&I counts) identified several trends in both the 90% and 95% confidence limit categories.

Downward trends were established for the data sets listed in Table 4-3 for F&I counts. Indeterminate trends were established for other F&I count data sets listed in Table 4-4.

Table 4-3. F&I Count Data Sets with Established Trends by the MK Statistical Test

Data Set	Confidence	
	90%	95%
Components of Distribution System (Serious Incidents Only)		
Mains		X
Polyethylene Mains		X
Polyethylene Service Lines		X
Corrosion on Mains	X	
Outside Force for Mains	X	
Outside Forces for Service Lines	X	
Outside Forces for Polyethylene Plastic Mains	X	
Outside Forces for Polyethylene Plastic Service Lines		X
Third Party Damage for Polyethylene Plastic Service Lines		X
All Parts of Distribution System (Serious Incidents Only)		
Construction/Operating Error		X
Outside Forces		X

Table 4-4. F&I Count Data Sets with Indeterminate Trends by the MK Statistical Test

Components of the Distribution System (Serious Incidents Only)
Total Distribution System
Meter Assemblies
Other Parts of System
Service Lines
Cast Iron Mains
Steel Service Lines
Corrosion for Service Lines
Outside Force for Cast Iron Mains
Outside Force for Steel Mains
Third Party Damage for Cast Iron Mains
Third Party Damage for Polyethylene Mains
Third Party Damage for Steel Mains
Earth Movement for Cast Iron Mains
Outside Force for Steel Service Lines
Third Party Damage for Steel Service Lines
All Parts of Distribution System (Serious Incidents Only)
Accidentally Cause by Operator
Corrosion

4.4 Major Findings

The major findings of this study can be classified as associated with:

- Serious incident and F&I count distributions by parts of the system, materials of construction, and causes;
- Yearly rates of Serious Incidents and F&I counts per 100,000 miles of mains or services, depending on which part of the distribution system is being examined, over the period 1990 to 2002; and
- Trends in various types of incidents or F&I counts.

The data and information in this study is intended as a resource for possible further investigations, as determined by the stakeholders involved in seeking ways to improve distribution pipeline safety performance. Major findings of the study are as follows:

- The average annual Serious Incident rate for the distribution system as a whole for the period 1990 through 2002 is 2.9 per 100,000 miles of pipeline. The overall Serious Incident rate is declining based on a statistical analysis of data for the years 1990 through 2002, with a 41% decrease over the 13-year study period.

- The Serious Incident rate per 100,000 miles varies with the parts of the system, materials of construction, and incident causes.

- Examination of Serious Incidents appears to be a way to measure safety performance for the distribution infrastructure in a consistent way over time by eliminating biases associated with uncertainties inherent in the use of the full distribution incident dataset. These uncertainties arise because the reported data include incidents reported at the discretion of the operator, and property damage cost estimates based on different estimating methods, rather than on an objective criterion such as the occurrence of fatalities and injuries with an incident.

- Of the six cause categories collected in the OPS database, outside force is the dominant cause category. This applies to all parts but varies among the parts of the system based on data from 1990 through 2002.

- Within outside force, third party damage is the dominant cause for all portions of the system:
  - Mains suffer 40% of all third party damage incidents;
  - Service lines suffer 41% of all third party damage incidents;
  - Meter set assemblies suffer 11% of all third party damage; and
  - "Other" and "No Data" information in the DOT database makes up 8% of all third party damage.

- With the exception of cast iron mains, third party damage is the dominant subcategory of outside forces for mains and service lines, contributing nearly 34.6% to the total number of Serious Incidents over the 1990 to 2002 period. For cast iron, earth movement is the dominant cause category with a 4.5% contribution to the total number of Serious Incidents.

- For mains and service lines, the highest percentage of outside force Serious Incidents are associated with the polyethylene plastic material of construction. Forty-two percent of outside force Serious Incidents for mains were associated with polyethylene and 29% were associated with cast iron. For service lines, 53% of outside force Serious Incidents were associated with polyethylene and 36% were associated with steel.

- Among all materials of construction, polyethylene mains and service lines also appear to have the highest normalized incident rates per 100,000 miles of pipe for third party damage. However, this cannot be a definitive conclusion based on the data above. The reason is that this study did not attempt to resolve areas that contribute so some uncertainty as to the predominance of polyethylene piping-related incidents. The likelihood of a third party hit is typically a strong function of the level of construction activity. A correlation between the presence of a particular gas pipe material and the level of construction activity is not available.

Further, a distinguishing factor for plastic as opposed to steel is that plastic is more likely than steel to instantaneously fail upon impact during excavation-related events. The effect of a strike on a buried steel pipeline may not be an instantaneous failure, but could ultimately result in a corrosion-related incident and thus be recorded as such.

- Trends can be established to 90% and 95% confidence levels with some of the time series of Serious Incidents classifications in this report, but not all. Using the MK test, downtrends over the study period are observed for the following:
  - Total Serious Incidents (95%);
  - Serious Incidents on Mains (95%);
  - Serious Incidents on Polyethylene Plastic Mains (95%);
  - Serious Incidents on Steel Mains (95%);
  - Serious Incidents Caused by Construction/Operating Error (95%);
  - Serious Incidents Accidentally Caused by Operator (90%);
  - Serious Incidents Caused by Corrosion (90%);
  - Serious Incidents Caused by Outside Force (95%);
  - Corrosion Serious Incidents on Mains (90%);
  - Outside Force Serious Incidents on Mains (95%); and
  - Third Party Outside Force Serious Incidents on Mains (90%)

- No trends could be inferred for a number of subsets of the serious incident data, based on the statistical test of the time series of incidents per 100,000 miles over the period 1990-2002.

5.0 INDUSTRY PRACTICES AND PROGRAMS

5.1 Purpose and Need

The major objectives of the industry practices and programs assessment and safety regulation review were to obtain:

- A "snapshot" of current and emerging operator processes, procedures and practices that address threats to distribution infrastructure and thus help maintain and enhance infrastructure integrity;
- A basis for evaluating the coverage of major threats to the distribution infrastructure by current federal and state safety regulations; and
- A listing of industry and government programs and initiatives that are currently in place addressing practices that cover distribution systems.

There was no attempt to evaluate the effectiveness of the current federal safety regulations in addressing each threat, but a question was included asking which provisions in the regulations are out dated or add little or no value to the integrity of the distribution infrastructure.

The primary tool to accomplish the above objectives was an industry practices questionnaire that was developed with input from industry and government representatives on the DISG and DIGIT. The entire industry practices questionnaire can be found in Appendix E.

5.2 Survey Group

The 36 operators, to whom the questionnaire was sent, were not selected based on a random sample of the industry as a whole. Rather, they were selected through guidelines established by the AGF, state utility and service commission safety representatives, and APGA as representative cross-section of the gas utility industry. Of the 36 who received the questionnaire, 24 are AGA members and 12 are APGA members.

Twenty-three of the 36 survey recipients (63.9%) responded to the survey. Fifteen of the respondents were AGA member companies and 8 were APGA member companies. In several cases, and for unstated reasons, only a subset of the 23 actually answered a particular survey question. In those cases, it has been assumed that the absence of an answer does not necessarily constitute an answer in the negative and was not counted as such.

The statistics of the group responding to the survey can be found in Appendix F. Their size range, in number of customers served, is given in Table 5-1, page 5-2.

Table 5-1. Size Range of Gas Companies Responding to the Survey

Number of Customers	Number of Respondents
10,000 or less	5
Greater than 10,000 but not more than 300,000	3
Greater than 300,000 but not more than 1,000,000	10
Greater than 1,000,000	5

This group represents companies with 26% of the nation's total number of gas customers, 23% of the installed miles of main and 24% of the number of services. Members of this group have been involved in 25% of incidents on mains and 18% of incidents on service lines between 1998 and 2002. While this group is not a statistically representative random sample of the entire population of distribution operators, they do provide insight on distribution operator practices and programs outside of 49 CFR Part 192. However, this also means that a confidence level cannot be determined as to their responses to the survey and how they would relate to the distribution industry as a whole.

5.3 Components of the Industry Practices Questionnaire

The questionnaire solicited operator responses in 7 sections:

Section 1

- Major differences between transmission pipeline systems and distribution infrastructure

- The level of significance of the eight major threat categories identified in ASME B31.8S. Stress corrosion cracking was not included since distribution systems do not operate under conditions normally associated with this threat. The list of threats was expanded to account for the use of materials in distribution pipeline systems that are not used for transmission (e.g., cast iron, plastic). As a result, 14 categories of threats were examined

- Other potential threats to distribution infrastructure, not identified in ASME B31.8S

Section 2

- Federal pipeline safety regulations that:
  - Address the threats to distribution infrastructure
  - Are outdated or add little value to distribution infrastructure integrity

- State pipeline safety regulations that exceed federal regulations

Section 3

- Current prevention and mitigation (P&M) measures that operators incorporate into design, construction, or operational practices that exceed minimum pipeline safety standards
- Use of performance measures by operators

Section 4

- Use of risk ranking in distribution system evaluations
- Attributes of one-call systems
- Participation in damage prevention organizations
- Formal programs / processes that address distribution infrastructure integrity
- Use of planned infrastructure replacement programs

Section 5

- Processes for Identification, evaluation and implementation of new technologies

Section 6

- Areas of concern not addressed in the questionnaire

Section 7

- Operator statistics of responders to the survey

5.4 Findings from Industry Practices Questionnaire

A compilation of the responses to the industry practices questionnaire can be found in Appendix G.

5.4.1 Major Differences between Transmission Facilities and Distribution Infrastructure

A majority of the respondents agreed that type of system (65.2%), type of materials (78.3%), system pressures (95.7%), and typical failure mechanism (69.6%) are all highly significant differences between transmission pipelines and distribution infrastructure. Location of facilities was given by 46.2% of the responders when answering the question relating to other significant differences between transmission pipelines and distribution systems. Section 3 of this report further discusses the differences between transmission and distribution systems.

5.4.2 Major Threats to Distribution Infrastructure

The industry practices survey asked respondents to prioritize threats to piping infrastructure. The threat classification in ASME Standard B31.8S – Managing System Integrity of Gas Pipelines was used as a starting point for defining the threats to distribution pipelines. In that standard, infrastructure threats are classified as:

A. Time dependent
   1. External corrosion
   2. Internal corrosion
   3. Stress corrosion cracking

B. Stable
   1. Manufacturing related (defective pipe seam, or defective pipe)
   2. Construction related (defective pipe girth weld, defective fabrication weld, wrinkle bend or buckle, or stripped threads/broken pipe/coupling failure)
   3. Equipment related (gasket O-ring failure, control/relief equipment malfunction, seal/pump packing failure, or miscellaneous)

C. Time independent
    1. Third party/Mechanical damage (damage inflicted by first, second, or third parties - instantaneous/immediate failure; previously damaged pipe - delayed failure mode; or vandalism)
    2. Incorrect operations (incorrect operational procedure)
    3. Weather related/Outside force (cold weather, lightning, heavy rains or floods, earth movements)

The threat of stress corrosion cracking (SCC) was excluded in the industry practices survey, as it is not typically a threat to the distribution infrastructure. SCC is the cracking of a pipeline from the combined influence of tensile stress and a corrosive environment. SCC is typically not considered a threat for distribution piping since distribution pipelines do not operate at pressures high enough to produce the stresses necessary to create an environment that could induce SCC.

On October 22, 2004, OPS published a draft of a comprehensive SCC Study written by Michael Baker Jr., Inc. According to the OPS web site, "the study has been designed to synthesize what is already known about the history of SCC, level of risk, indicators of the potential for SCC, detection methods, mitigation measures, assessment procedure, and actions taken by pipeline operators to facilitate response to SCC-related incidents." As part of its study, Michael Baker Jr., Inc. disseminated a survey to various pipeline operators querying operator's experiences in experiencing and observing SCC. Among the local distribution companies responding to this survey, none indicated ever experiencing SCC on their pipeline systems.

For transmission pipelines, the material of construction is predominantly steel, which can be coated and wrapped or bare. The materials found in distribution pipeline systems are predominantly steel or polyethylene plastic, with some cast iron, wrought iron, other plastic and copper. With the different materials taken into account and in view of the incident causes, these 9 threats were expanded to the following 14 categories of threats for distribution systems (hereinafter simply referred to as "threats"):

1. External Corrosion Coated and Wrapped Pipe
2. External Corrosion Bare Steel Pipe
3. External Corrosion Cast Iron Pipe
4. Internal Corrosion
5. Manufacture-Related Defects Steel Pipe (defective pipe seam, defective pipe)
6. Manufacture-Related Defects Plastic Pipe (defective piping material, defective pipe, defective piping component)
7. Construction-Related Defects Steel Pipe (defective pipe girth weld, defective fabrication weld, or stripped threads/broken pipe/coupling failure)
8. Construction-Related Defects Plastic Pipe (defective fusion, installation error of pipe or piping component, improper backfill)
9. Equipment Malfunction (gasket O-ring failure, control/relief equipment malfunction, seal failure, piping component failure)

10. Excavation /Mechanical Damage (damage inflicted by first, second, or third parties - instantaneous/immediate failure; previously damaged pipe - delayed failure mode; excavation undermining of pipe; vandalism)
11. Incorrect Operations & Operator Error (incorrect operational procedure)
12. Outside Force/Weather Steel Pipe (cold weather, electrical surge, heavy rains or floods, earth movements)
13. Outside Force/Weather Cast Iron Pipe (cold weather, heavy rains or floods, earth movements)
14. Outside Force/Weather Plastic Pipe (cold weather, lightning, heavy rains or floods, earth movements)

Threat No. 3 above (external corrosion of cast iron pipe) is the name given here to the phenomenon of graphitization of cast iron pipe. Cast iron contains carbon, in the form of graphite, in its molecular structure. It is composed of a crystalline structure as are all metals; i.e. it is a heterogeneous mass of crystals of its major elements (Iron, Manganese, Carbon, Sulphur and Silicon). One condition, which can occur in the presence of acid rain and/or seawater, is "graphitization". The stable graphite crystals remain in place, but the less stable iron becomes converted to insoluble iron oxide (rust). The result is that the cast iron piece retains its shape and appearance but becomes weaker mechanically because of the loss of iron. Graphitization is not, however, a common problem. It generally will occur only after bare metal is left exposed for extended periods, or where failed joints allow the penetration of acidic rainwater to interior surfaces. This corrosion process is galvanic, with the carbon present acting as the most noble (least corrosive) element and the iron acting as the least noble (most corrosive) element. The composition or microstructure of the iron affects the durability of the object because the rate of corrosion is dependent upon the amount and structure of the graphite present in the iron.

Table 5-2 shows the survey results where the 23 respondents classified the threats to the distribution infrastructure by severity as being "Significant", "Medium", or "Low/No Threat" (see Survey Section 1 in the compilation of responses in Appendix G). The highest percentage of respondents identified weather-related outside force on cast iron as the most significant threat followed by (90%) excavation/mechanical damage (87%).

Table 5-2. Operator Perceptions on Threat Significance

Classified as "Significant" to "Medium" Threat	% Respondents
1. Outside Force/Weather Cast Iron Pipe	90
2. Excavation /Mechanical Damage	87
3. External Corrosion Bare Steel Pipe	86
4. External Corrosion (graphitization) Cast Iron Pipe	71
5. External Corrosion Coated & Wrapped Pipe	69
6. Construction-Related Defects Plastic Pipe	57
7. Outside Force/Weather Steel Pipe	49
8. Construction-Related Defects Steel Pipe	48
9. Incorrect operations & Operator Error	35
10. Equipment Malfunction	35
11. Manufacture-Related Defects Plastic Pipe	30
12. Outside Force/Weather Plastic Pipe	26
13. Internal Corrosion	22
14. Manufacture-Related Defects Steel Pipe	22

5.4.3 Federal and State Regulations Addressing Threats to Distribution Infrastructure

Table 5-3, page 5-7, consolidates the 23 responses relative to distribution threats addressed by Subpart of Title 49 of the Code of Federal Regulations (CFR) Part 192. An "X" in the table designates that 10 or more respondents indicated that the requirements within the subpart address the corresponding specific distribution infrastructure integrity threat.

The respondents indicated that in addition to the federal requirements, 13 of the 26 states in which the respondents operate have enacted regulations that exceed the federal requirements in 49 CFR Part 192. States have issued additional pipeline safety regulations that exceed the requirements of every Subpart of 49 CFR 192, except Subpart C – Pipe Design. The number of states that enacted the additional regulations varies by Subpart.

Table 5-3. Respondents' Perception on Whether Part 192 Addresses Threats to Distribution

	Threat to Distribution Infrastructure													
Subpart Title	External Corrosion Coated & Wrapped Pipe	External Corrosion Bare Steel Pipe	External Corrosion Cast Iron Pipe	Internal Corrosion	Manuf. Related Defects Steel Pipe	Manuf. Related Defects Plastic Pipe	Const. Related Defects Steel Pipe	Const. Related Defects Plastic Pipe	Equipment Malfunction	Excavation/Mechanical Damage	Incorrect Operations & Operator Error	Outside Force / Weather Steel Pipe	Outside Force / Weather Cast Iron Pipe	Outside Force / Weather Plastic Pipe
Subpart A General	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Subpart B Materials	X	X	X	X	X	X	X					X	X	X
Subpart C Pipe Design					X	X		X				X	X	X
Subpart D Design of Pipeline Components					X	X	X	X	X	X	X	X	X	X
Subpart E Welding of Steel Pipelines							X				X			
Subpart F Joining of Materials other than by Welding								X			X	X	X	X
Subpart G Gen. Construction Req'ts. for Trans. Lines and Mains					X	X	X	X		X	X	X	X	X
Subpart H Customer Meters, Svc Regulators and Svc Lines	X					X	X	X	X	X	X	X	X	X
Subpart I Req'ts. for Corrosion Control	X	X	X	X			X				X			
Subpart J Test Requirements					X	X	X	X			X			
Subpart K Uprating	X	X		X	X	X	X	X	X	X	X			
Subpart L Operations	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Subpart M Maintenance	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Subpart N Qual. of Pipeline Personnel	X	X	X	X			X	X	X	X	X	X	X	X

5.4.4 Obsolete / Minimum Value Regulations

The responders identified numerous current regulations that they consider obsolete or which they believe add minimum value to distribution infrastructure integrity. The regulations listed below were selected as most relevant to this study from the responses. All of the responses can be found in Appendix G include the more significant ones as related to addressing threats to distribution infrastructure:

§192.201 Required capacity of pressure relieving and limiting stations

For systems operating at or below 125 psig, where the strength of steel piping and components is not an issue, there should be provisions to allow the systems to operate at up to 10% over the established MAOP to ensure adequate gas flow and pressures under emergency conditions. Current code language is inflexible for accommodating winter emergency conditions when gas outages potentially become a higher safety risk than operating the system over the established MAOP.

§192.609 Change in class location: Required Study.

Class locations make sense primarily in the transmission system context.

§192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

Class locations make sense primarily in the transmission system context.

5.4.5 Use of Additional Prevention and Mitigation (P&M) Measures

In Section 3 of Appendix E, the industry practices questionnaire, the survey group was asked to identify additional P&M measures, in excess of those required by 49 CFR Part 192, that they employ to ensure the integrity of their distribution infrastructure.

Respondents identified additional P&M measures they voluntarily employ, in excess of those required by 49 CFR Part 192, to address specific instances for each of the 14 threats to the distribution infrastructure. Operators take additional P&M measures based on climate, geography, composition of the distribution system, operating pressure, and many other factors. All respondents indicated they were implementing additional P&M measures but not all responders were implementing additional P&M measures for each threat. The percentages of operators implementing additional P&M measures for a particular threat ranged from 17% to 58%. As shown in Table 5-4, page 5-9, the top three highest percentages were to address:

1. External corrosion on bare steel pipe;
2. Weather-related outside force damage to cast iron pipe; and
3. External corrosion (graphitization) of cast iron pipe.

In total, the responders listed 190 additional P&M measures, in excess of those required by 49 CFR Part 192 for distribution systems. Refer to Section 3 of the compilation of responses in Appendix G for details on these responses. For reasons of confidentiality, the number of measures each individual operator uses for each threat was not compiled for this report.

The table shows that operators apply the greatest number of P&M measures exceeding the code to the threat of external corrosion on coated and wrapped, cathodically-protected steel pipe. Operators apply the second highest number of P&M measures to the threat of excavation/mechanical damage.

Of the P&M measures listed, 84% follow formal written processes, and 44% have performance measures in place.

Table 5-4. Responses on P&M Measures in Excess of the Federal Regulations

	Threat to Distribution Infrastructure													
	External Corrosion (Coated & Wrapped Pipe)	External Corrosion (Bare Steel Pipe)	External Corrosion (Cast Iron Pipe)	Internal Corrosion	Manufacturing Defects (Steel Pipe)	Manufacturing Defects (Plastic Pipe)	Construction Defects (Steel Pipe)	Construction Defects (Plastic Pipe)	Equipment Malfunction	Excavation / Mechanical Damage	Incorrect Operations & Operator Error	Outside Force / Weather (Steel Pipe)	Outside Force / Weather (Cast Iron Pipe)	Outside Force / Weather (Plastic Pipe)
Number of Survey Group Respondents With P&M Measures Exceeding Part 192 regulations	10	10	8	9	8	8	10	10	6	10	10	9	8	4
Percentage of Survey Group With P&M Measures Exceeding Minimum Safety Standards	43%	58%	47%	41%	35%	35%	43%	43%	27%	43%	43%	17%	50%	35%
Total Number of Additional P&M Measures Cited By the Responding Group	25	16	9	12	10	11	13	14	12	22	18	6	13	9

Feedback received from some operators after the survey was completed also indicated a certain level of uncertainty in identifying a measure as exceeding certain portions of the code. The uncertainty typically arose in those cases where a particular portion of the pipeline safety code is a performance-oriented rule, and thus open to various interpretations as to what is required to meet the expectations of the code and what would be considered in excess of regulatory requirements.

The industry practices questionnaire also asked operators to rate the perceived level of significance of a threat. This was summarized in Table 5-2 of this report. Table 5-4 presented the survey results of P&M measures in excess of federal regulations. To permit further analysis, the statistics in Tables 5-2 and 5-4 are shown side-by-side in Table 5-5 with the percentages of serious distribution incidents by cause. The incident statistics for "Other" and "No Data" have not been included in Table 5-5.

Table 5-5. Use of P&M Measures beyond Federal Code Requirements

Threat		Respondents That*:	
	% of all serious distribution incidents	Consider threat to be significant	Employ P&M measures in excess of 49 CFR Part 192
Outside Force	46.6%		
1. Outside Force/Weather Cast Iron Pipe		90%	50%
2. Excavation /Mechanical Damage		87%	43%
3. Outside Force/Weather Plastic Pipe		26%	35%
4. Outside Force/Weather Steel Pipe		49%	17%
Corrosion	6.5%		
5. External Corrosion Bare Steel Pipe		86%	58%
6. External Corrosion Cast Iron Pipe		71%	47%
7. External Corrosion Coated & Wrapped Pipe		69%	43%
8. Internal Corrosion		22%	41%
Construction/Operating Error	9.8%		
9. Construction-Related Defects Steel Pipe		48%	43%
10. Construction-Related Defects Plastic Pipe		57%	43%
11. Manufacture-Related Defects Steel Pipe		22%	35%
12. Manufacture-Related Defects Plastic Pipe		30%	35%
13. Equipment Malfunction		35%	27%
Accidentally Caused by Operator	9.8%		
14. Incorrect Operations & Operator Error		35%	43%

* Note: Appendix G is the source of these statistics

The number of P&M measures used by the operators also varied with the threat.

Comparison of percentage variations relative to each other in each column in Table 5-5 shows several features, namely:

a. The two threats seen as most significant by the operators also are the ones that most often have additional P&M measures applied. To explain further, the operators surveyed perceived the most significant threats to be outside force/weather of cast iron pipe (90%), excavation/mechanical damage (87%), and external corrosion of bare steel pipe (86%). The percent of operators surveyed that employed additional P&M measures was also greatest for the threat of outside force/weather of cast iron pipe (50%) and the threat of external corrosion of bare steel (58%).

b. This appears not to be true for excavation damage, which was perceived as the second most significant threat. Table 5-5 shows that only 43% of the operators use P&M measures exceeding code requirements to address this threat, even though 87% of the operators perceive it as a significant threat. The reason for this is not known in the absence of additional research beyond the scope of this study.

   This apparent inconsistency was discussed with industry members of DISG. These operators voiced a concern that this part of the survey was probably misinterpreted. It was noted that over 95% of the respondents actively participate in a national, regional, state or local damage prevention organization (Section 5.4.8) and the total number of extra P&M measures applied to third party damage is correspondingly the second highest, as shown by the last row in Table 5.4.

Moreover operators are involved in avoiding damage to the distribution systems by taking actions such as: third-party construction project pre-planning; pipe relocation performed to accommodate known pending third party excavation; cut-and-reconnect programs to avoid damage to service pipe during third party construction projects; standby and monitoring of third party excavation; temporary support of pipe on deep ditch third party construction; and use of ads in the media to promote "call before you dig" messages.

c. Other areas in Table 5-5, in order of decreasing difference, where the perceived significance of the threat is markedly higher than the percentage of operators applying extra P&M measures are for the threats of outside force/weather steel pipe, external corrosion coated and wrapped pipe, external corrosion (graphitization) cast iron pipe, and construction-related defects plastic pipe. Table 5-4 shows that the highest number of extra P&M measures (25 measures) is applied by operators to deal with external corrosion on coated and wrapped steel pipe.

d. Table 5-5 also indicates areas where the percentage of operators applying additional P&M measures is markedly higher than the percentage perceiving the threat as significant. This includes the area of internal corrosion, outside force/weather plastic pipe, manufacturer-related defects: steel pipe, and incorrect operations and operator error.

The reason for the apparent discrepancies in relative percentage variations between the two columns cannot be determined without additional investigation. Through discussions with some of the survey participants, in some cases it appears to be tied to the interpretation of performance-oriented regulatory requirements. For example, because the pipeline safety code only states that operators must carry out a written program to prevent excavation damage to their pipelines, operators do not naturally consider many of their existing processes as exceeding the code. Some of this data may be available from state-maintained databases, but its compilation was not part of the effort leading to this report.

5.4.6 Use of Risk Ranking in Evaluation of Distribution Infrastructure

Risk ranking models evaluate both the likelihood and the severity of consequences of an incident.

Of the 23 companies that responded to the survey, 19 (82.6%) use risk-ranking models either formally or informally in the evaluation of their systems. Further, 17 of these 19 operators follow a formal, written process. Refer to Section 4.01 of the survey compilation in Appendix G.

5.4.7 One-Call Systems in Respondents' States

Of the 23 respondents, 22 replied to the questions in Section 4 of Appendix E. Because some of them operate multiple states, there were 29 separate entries in the survey response to cover individual state damage prevention programs. The 29 responses are compiled in Section 4 of Appendix G. Of these,

- Three responses did not perceive a noticeable decline in number of hits during excavation since inception of the one-call system, even though in all cases the state levied penalties and fines against violators;
- Three responses did not address the question of decline in number of hits;
- Twenty three responses perceived a noticeable decline in number of hits even in those states where no penalties or fines were levied against violators;
- Three did not have state-mandated participation in one-call system, but still perceived a decline in the number of hits;
- Certain parties are exempt from participation in one-call systems in 19 of the 29 states;
- Ten have mandatory reporting of excavation damage; and
- One-call regulations and legislation exist in 24 of the 29 states covered by the respondents, with provisions for levying penalties and fines.

Without further specific questions, no major findings can be drawn from the above results. It should be noted that one-call systems, excavation damage prevention programs, the penalties and fines levied against violators, and enforcement actions vary dramatically from state to state.

5.4.8 Participation in Damage Prevention Councils/Organizations

Twenty-two respondents (95.7%) indicated they actively participate in local, state, regional and national damage prevention councils and organizations. These 22 respondents indicated they participate in a tot of 43 damage prevention councils and organizations, an average of almost 2 per respondent. Thirteen respondents (56.5%) cited involvement with the Common Ground Alliance (CGA), making the CGA the most prominent damage prevention organization. among respondents.

5.4.9 High Impact Processes

Eighteen survey respondents (78.3%) identified formal processes that have the highest impact in addressing and mitigating the consequences of threats to the distribution infrastructure. This is presented in Section 4 of Appendix G.

While the responses where widely varied, operators identified four processes currently required by federal regulation that have the largest impact on distribution infrastructure integrity. These are:

- cathodic protection systems (10 respondents);
- leak surveys (10 respondents);
- operator qualification programs (8 respondents); and
- one-call systems (4 respondents).

Although not required by federal regulation, a pipe replacement or management program to address corrosion, as with bare steel pipe, or low resistance to earth movement, as with cast iron, was also identified as a high impact process.

The fourth bullet (one-call systems) seems to cover an unusually small number of respondents, given that excavation damage is perceived as a highly significant threat and there is consensus in the industry that one-call systems have a high effect in helping prevent excavation damage. Question 4.04 of Appendix E did not offer a menu of answer choices. It is widely known that most gas utilities participate as members in one-call systems and support one-call centers as facility owners. Subsequent communication with some of the respondents indicates that participation or activities in one-call systems may have been misinterpreted as part of a process external to the operator's company. As such, when considering operator processes for high impact, some operators may have overlooked one-call systems. Except for pipe replacement or management programs, all of these measures are required by regulation.

5.4.10 Infrastructure Replacement Programs

A planned replacement program is a P&M measure that targets higher risk segments of the distribution infrastructure. Operators identify higher risk segments based on the pipeline's material and environmental conditions surrounding the pipeline.

Of the 23 companies surveyed, 15 respondents (65%) have a planned replacement program for their cast/ductile iron systems. Nine of the 15 follow formal, written programs that have been presented to their state regulatory body. Two of the 15 have projected completion dates.

Seventeen of the 23 respondents (74%) have a planned replacement program for their bare steel main systems. Twelve of the 17 follow formal, written programs of which eight have been presented to their state regulatory body. Three of the 17 have projected completion dates.

Pipe replacement between 1990 and 2002 has reduced the amount of cast iron main mileage by 21% and the amount of bare, unprotected steel main mileage by 7%. During the same period, the number of bare, unprotected steel services has been reduced by 13%.

Two respondents (9%) have a planned replacement program for specific types of plastic piping or certain older vintage plastic piping systems. Both follow formal, written programs and one of these programs has been presented to their state regulatory body. Neither of the two has a projected complete date.

It should be noted that current federal regulations do not specifically require management of bare steel or cast iron pipe. However, current federal regulations require pipeline operators to employ bare steel and cast iron pipe maintenance and remediation measures.

The net effect of the infrastructure replacement programs and the change in materials used for initial installation, between 1990 and 2002, is shown by a comparison of materials of construction in distribution mains and services in the U. S. This is shown in Figure 5-2.

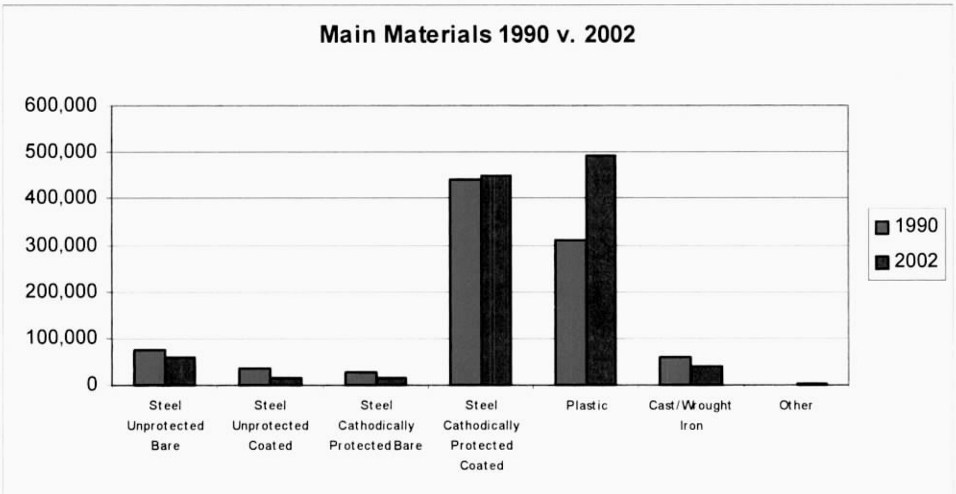


Figure 5-2a. Change in Materials of Distribution Main Construction

Pipe replacement and a change in materials used for initial installations between 1990 and 2002 has reduced the amount of cast iron main mileage by 21% and the amount of bare, unprotected steel main mileage by 7%. During the same period, the number of bare, unprotected steel services has been reduced by 13%.

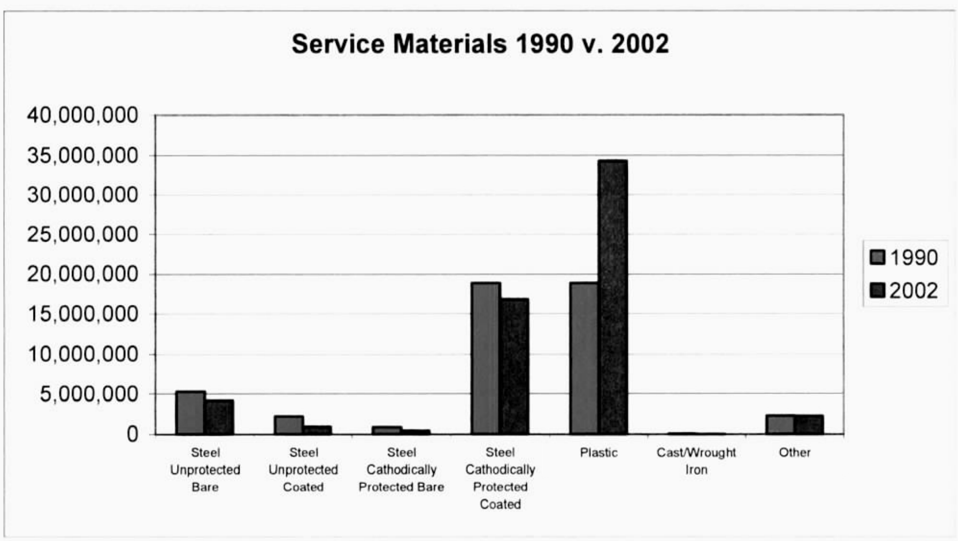


Figure 5-2b. Change in Materials of Distribution Service Line Construction

The percent change in the "market share" of distribution piping materials is shown in Figure 5-3.

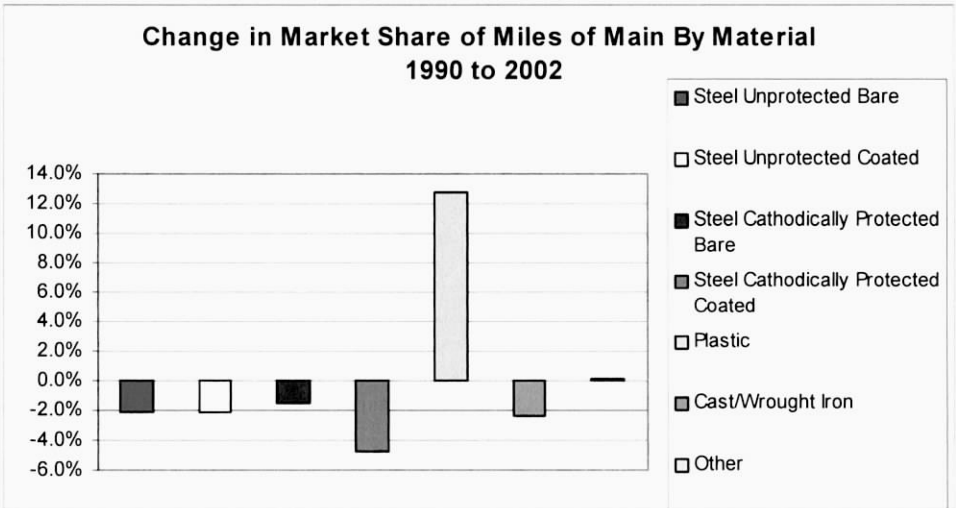


Figure 5-3a. Change in Percentage Materials of Distribution Main Construction

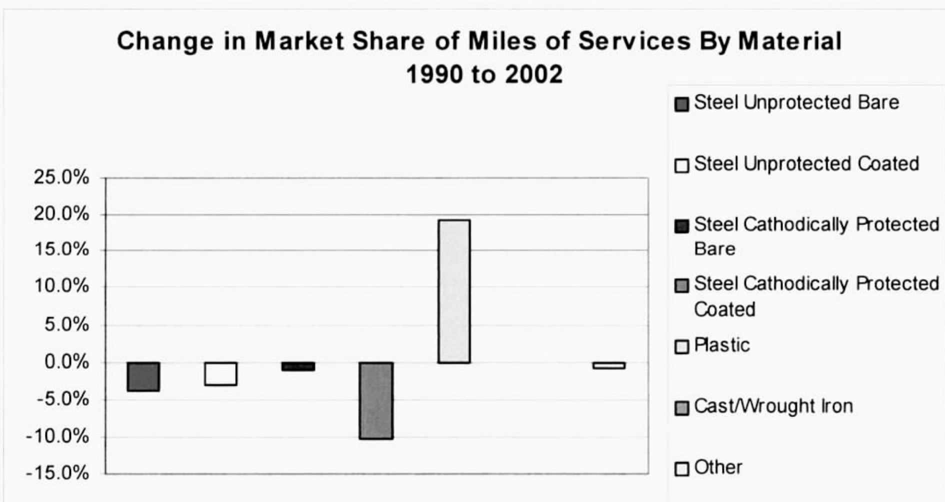


Figure 5-3b. Change in Percentage Materials of Distribution Service Line Construction

The nationwide percentages of the various materials of construction for distribution systems are shown in Table 5-6, below.

Table 5-6. Percentages of Distribution System Materials of Construction[3]

Material of Construction	1990 Main %	1990 Service Line %	2002 Main %	2002 Service Line %
Steel Unprot. Bare	7.8	10.9	5.7	7.1
Steel Unprot. Coated	3.7	4.8	1.5	1.6
Steel Protected Bare	2.8	1.9	1.3	0.8
Steel Cathodically Protected & Coated	46.4	38.7	41.7	28.5
Plastic	32.9	38.7	45.7	58.1
Cast Iron	6.2	0.1	3.8	0.1
Other	0.2	4.9	0.3	3.9

Together with Table 5-6, Figure 5-3 shows that the percent of cast iron pipe in mains changed from 6.2% in 1990 to 3.8% in 2002 or a decrease of 2.4 percentage points in the market share. The percent of bare unprotected steel the system decreased by 2.1 percentage points for mains (from 7.8% to 5.7%) and 3.8 percentage points for service lines (from 10.9% to 7.1%). Conversely, between 1990 and 2002, plastic captured an additional 12.7 percentage points of the market share for mains and 19.4 percentage points for services. These statistics clearly show that modern materials of construction such as cathodically protected steel and polyethylene plastic are becoming more predominant. Furthermore, these statistics also show that the share of steel pipelines in distribution is also dropping, in favor of plastic. The higher use of plastic will tend to lower the effect of the time dependent threat of corrosion on the distribution system.

However, the experience with plastic pipe is of a shorter duration than with steel pipe. Some of the earlier plastic materials have shown poor performance in service. The Gas Technology Institute extensively studied this in the 1990s. Early plastic materials used in distribution systems included polyvinyl chloride (PVC), acrylonitrile butadiene-styrene (ABS), cellulose acetate butyrate (CAB) and others. Polyethylene (PE) plastic pipe, the dominant material for new plastic installations, began to be used for gas distribution in the mid-sixties. Today it exists in two grades: high-density and medium density.

Plastic materials performance has been monitored since the beginning of 2001 by the government-industry Plastic Pipe Database Committee (PPDC), which oversees a database of in-service plastic material failure data. This data are being been collected by AGA through a voluntary effort by 160 gas utilities and the database is examined periodically, when the PPDC meets. The database now covers over 60% of the plastic mains and services installed in the U.S. The data being collected are shown in Appendix N.

[3] Source: DOT Annual Report

The PPDC recently examined the data for additional insight on plastic piping failures, such as the type of plastic material, manufacturer, date and method of installation, installed environment, and failure date, location and apparent cause. Although insufficient for a root cause analysis, this level of detail provides the PPDC with the ability to identify potential areas of concern involving plastic piping materials. This level of detail is not provided in the DOT incident reports.

It was the joint conclusion of the PPDC members that, at the time of writing of this report, the information gleaned from the failure database reinforces what is historically known about certain older plastic piping materials and components[4]. Some of these were identified in 2000 by a government-industry group[5] and have resulted in an OPS Advisory Bulletin[6]. The bulletin can be found on the OPS website at http://ops.dot.gov, under "What's New" and then under "What's New Previous Year Link 2002". The historically known information covers the following materials and components:

1. Polyethylene (PE) pipe manufactured by Century Utility Products;
2. Pre-1973 DuPont Aldyl A low ductile inner wall plastic pipe;
3. PE pipe containing PE 3306 resin;
4. Delrin insert tap tees, with failure likely due to over-tightening of the cap; and
5. Plexco service tee Celcon (polyacetal) cap, with failure likely due to over-tightening of the cap.

Total installed and in-service mileage data for these earlier resin materials is not readily available. Operators are to report them under the "Other Plastics" section of the Annual Report for Distribution Systems. Many companies have since removed these materials from their systems. Some continue to remove them, but on an exception basis, as it has been demonstrated that these materials will perform properly, absent certain stressors[7]. The degree to which these materials are being replaced has not been assessed by this study nor is data being consistently or systematically collected on the rate of replacement.

5.5 Recent Initiatives and Programs

One of the goals of this study was to capture the industry and government initiatives that are currently in-place that ensure continual improvement in regulation and practices and identify any potential improvements towards that objective.

[4] Plastic Pipe Data Collection and Sharing Initiative, Annual Progress Report, January 25, 2004

[5] Robert J. Hall, *Brittle-Like Cracking of Plastic Pipe,* Final Report No. DTRS56-96-C-0002-006, General Physics Corp., Columbia, Maryland, August 2000.

[6] OPS Advisory Bulletin ADB-02-07, *Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe,* Federal Register, Volume 67, Number 228, p. 70806, November 26, 2002 and Federal Register, Volume 67, Number 232, p. 72027, December 3, 2002.

[7] S. Lawrence Paulson, *Cracking Down on Plastic Pipe,* American Gas magazine, March 2000, pp. 23-26.

Since the passage of the 2002 pipeline safety reauthorizing legislation, there have been at least 12 mandates and initiatives under way addressing the integrity of distribution systems. Many of these resulted directly from pipeline safety legislation while others came from regulatory initiatives by the OPS Office of Pipeline Safety. Those resulting from legislation and affecting distribution systems include:

1. Direct assessment standards development
2. Environmental repair permit streamlining
3. One-call 3-digit number rulemaking
4. Right-of-way population encroachment study
5. Operator qualification standard development
6. Public awareness communication effectiveness rulemaking
7. Infrastructure R&D grants program

Current federal regulatory initiatives for distribution systems include:

1. Operator qualification rule revision
2. Public communications standard development
3. Better crisis communication
4. Excess flow valve installation
5. Operator safety performance metrics

In addition, a number of voluntary programs are in place aimed at providing further insight or addressing systematic approaches in dealing with areas considered important to distribution system integrity.

1. The Plastic Pipe Data Collection Project
2. Ensuring the quality of plastic piping materials
3. Common Ground Alliance
4. Industry consensus standards development

These programs are briefly described in Appendix O. Several of these were originally aimed at addressing issues on transmission pipelines. These include environmental repair permit streamlining, right-of-way population encroachment and better crisis communication. However, these will likely also provide insights and speed up learning on possible approaches to dealing with distribution pipelines.

6.0 REVIEW OF LEAK AND UNACCOUNTED FOR GAS DATA

The DIGIT recommended a review of available data regarding leaks repaired, leaks detected, leaks scheduled for maintenance and percent of unaccounted for gas as reported by operators in the gas distribution system annual reports submitted to OPS. For this study, limitations in the available data preclude assessing the overall integrity performance of natural gas distribution systems due to considerations and qualifications listed in Appendix M of this report. The main reasons are summarized below.

1. Because of the lack of specificity in the instructions for this part in the OPS annual report, operators have not consistently reported the number of leaks eliminated on occasion of pipeline replacement; some have counted it as 0 or 1 repair, while a few may count all the individual leaks on the replaced segments.

2. An increase in newly identified leaks could also be a positive safety indicator if operators' leak survey programs are becoming more effective. However, because in the OPS annual report, operators are not required to report newly identified leaks during the year, this data was not available.

3. No direction is given to operators, via the OPS' "Instructions For Completing Form RSPA F 7100.1-1 (Annual Report For Calendar Year XXXX – Gas Distribution System)", as to what to report under Part C – Number of Known System Leaks At End of Year Scheduled For Repair (see Exhibit B). Therefore, it is not possible to distinguish between various grades of leaks (frequently 3 grades, according to potential hazard posed), from the more hazardous requiring immediate or future repair, to those least hazardous, that can be monitored for a long time before they are repaired.

Because studies performed by the Gas Technology Institute[1] have shown that unaccounted for gas is primarily due to measurement and accounting errors, it is doubtful this information could provide meaningful data. The instructions for RSPA Form F 7100.1-1 do not specify what should be included under the "appropriate adjustments" factor in the % of unaccounted for gas formula. Thus, it becomes impossible to extract the gas lost through leakage to the atmosphere. Many operators report zero or even negative unaccounted for gas. Refer to Appendix M for additional discussion and details.

[1] Confidential study performed by the Gas Research Institute (has been renamed the Gas Technology Institute) in late 80s. See also *Finders of Lost Gas*, American Gas Magazine, May 1991.

7.0 GAP ANALYSIS

7.1 Purpose and Need

The purpose of this section is to provide a high level analysis of gaps in three areas:

1. Gaps between threats to the distribution infrastructure and industry practices;
2. Gaps between threats to distribution infrastructure and safety regulations; and
3. Gaps in data that inhibit a full determination of safety performance.

7.2 Gaps Between Threats and Industry Practices

The main tool used for identifying gaps between the threats to distribution infrastructure and industry practices that address these threats is the compilation of responses to an industry practices survey described under Section 5 of this report, coupled with the analysis of the safety performance described in Section 4 of this report.

From the responses received from operators to the industry survey questions, there were no obvious gaps between threats to distribution infrastructure and industry practices employed by operators.

7.3 Gaps Between Threats and Current Safety Regulations

The industry practices survey was also the basis of the analysis identifying gaps between threats to distribution infrastructure integrity and current federal pipeline safety regulations that address the threats. The survey respondents indicated that there are regulations that relate to each of the threats identified as applicable to distribution piping (that is, that no threat is totally unaddressed by regulation). However, the information gathered from the respondents does not allow any conclusions to be reached regarding the effectiveness with which these threats are addressed by the regulations.

In addition, the respondents indicated that many states have implemented additional safety regulations that supplement the requirements in as many as 13 of the 14 Subparts of 49 CFR 192. The only subpart not covered was Subpart C – Pipe Design.

Although this study did not evaluate effectiveness of current pipeline safety regulations, the survey group did identify individual regulations that, in their opinion, were obsolete or added little or no value to distribution infrastructure integrity. As shown by Section 5.4.4 of this report, respondents indicated three sections in the code that should be considered for review and possible modification or removal. They fall into two areas:

- Ability to operate above the maximum allowable operating pressure (up to 10% over established value) to enable gas to be supplied to customers under emergency conditions. This has been submitted in a November 26, 2002 petition for rule change to OPS by the State-Industry Regulatory Review Committee; and
- Class location studies and changes, which should be applicable only to transmission pipelines.

7.4 Gaps in Data

This section addresses gaps that were identified through the distribution safety performance analysis in Section 4, and the leak and unaccounted for gas data analysis in Section 6. Also addressed are gaps in connection with areas where further insight into possible improvements or enhancements is precluded due to lack of compiled knowledge or data. Whenever possible, the reasons for the shortcoming or obstacle are identified.

7.4.1 Leak Repair Data

The data supplied by operators to OPS on the Annual Report for Gas Distribution Systems include the leaks repaired/eliminated during the year and the leaks scheduled for repair at the end of the year. Not included in the reporting are all leak repairs pending and leaks identified during the reporting period.

As described in Section 6, attempts to analyze the OPS gas distribution system annual leak statistics as a measurement of safety performance were unsuccessful. The gas leak information from the OPS database yielded inconclusive results because it does not contain all of the information necessary to take a complete annual inventory of all pending and newly identified leaks.

Also, apparent vagueness in the instructions for Part C of the OPS Distribution annual report form (see Appendix I) could cause inconsistencies in how the numbers of leaks are reported, with not all operators counting the number of leaks eliminated in the same way.

7.4.2 Lost and Unaccounted For Gas Data

Past studies have shown that the unaccounted for gas statistics are primarily a result of accounting and measurement errors. Gas lost through leakage to the atmosphere is a comparatively small amount. Also, since the instructions for RSPA Form F 7100.1-1 do not specify what should be included under the "appropriate adjustments" factor in the percent unaccounted for gas formula, it becomes impossible to extract from the data the amount of gas lost through leakage to the atmosphere.

7.4.3 "Other" Incident Causes

The category of incidents labeled "Other" in the OPS incident database includes incidents reported by operators as not falling into one of the other five major cause categories. The instructions for the OPS incident form that gathers the data for the agency's database are not specific enough to preclude ambiguity and uncertainty. A member of the industry team participating in this study made a brief review of the entries associated with incidents marked as "Other" in the database. This review indicated that about 18% of the incidents under this category could involve portions of the gas delivery system, such as the customer's premises, that are outside the jurisdiction of the pipeline safety regulations. Based on the information currently in the OPS incident database, used in this study, it is not possible to drill down further to identify further causes under the "Other" category.

However, there is currently an on-going effort by OPS to further discriminate the detailed causes of the incidents in this category by examining each individual incident report. Since 27% of Serious Incidents are in this "Other" category, the accuracy of findings about the industry statistics, associated with jurisdictional assets, is somewhat impaired. This shortcoming was recently addressed by OPS through a revision of the incident report form. The revised form includes a menu of 25 causes replacing the original 5 causes under the "Apparent Cause" part of the incident reporting form. However, data collection only began in March 2004 and, as pointed out under subsections 7.4.6 and 7.4.7, some gaps still exist in the data to be collected.

7.4.4 "No Data" Incident Causes

Similar to the "Other" category, this category includes incidents with unknown characteristics or unresolved apparent causes. In this case, the operator did not check any of the cause boxes, including the "Other" category. Without further analyzing the individual incident reports and in some cases, other accident reports (such as for example NTSB accident reports), it is not possible to determine if these incidents apply to the regulated portion of the distribution system. As already verified in one case (refer to Section 4.3.7 - Other and No Data), this data set may be a source of uncertainty in the fatality and injury data.

7.4.5 Property Damage Data

Traditional analysis of pipeline safety statistics typically has considered the total number of incidents over a given period. In addition to incidents that involve fatalities and injuries, this also involves incidents that only resulted in property damage or in the opinion of the operator was significant enough to report. The property damage incidents are measured in dollars and are subject to uncertainties because the guidelines for determining the costs incurred due to the incident are not specific enough to ensure uniform reporting. Further, if the costs of gas lost are included in the property damage, the data will be a function of rising gas costs.

Another area that has been ignored in reporting requirements is the effect of inflation on the analysis of incidents involving property damage. The threshold for damage reporting was changed from $5,000 to $50,000 in 1984. Since then, no adjustment for inflation has been made. Without taking the cumulative effect of inflation into account, less costly incidents near the $50,000 threshold are included in the incident database. The longer the timeframe inflation is not taken into account, the greater the distortion. For example, $50,000 in property damage in 1990 is equivalent to $68,800 in 2002 after adjustment for inflation[1]. Therefore, the true value of property damage by distribution incidents is unknown, a major gap in evaluating performance.

7.4.6 Excavation Damage Data

Since outside force is the most significant threat from a safety statistics viewpoint and a highly significant threat as perceived by 87% of the operators surveyed, additional data that would provide an insight into all of the causes of outside force is highly desirable, yet mostly unavailable today. Using its Damage Information Reporting Tool, The Common Ground Alliance (CGA) has started collecting data on excavation damage on a voluntary basis from many underground utilities.[2]

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[1] US Department of Labor, Bureau of Labor Statistics, www.bls.gov.
[2] Common Ground Alliance Damage Information Reporting Tool (DIRT) Users Guide, October 28, 2003.

This data for excavation damage to gas piping, though useful, may not be sufficiently detailed to point to the most effective solutions. This includes for example, the levels of enforcement of excavation damage prevention laws, other incentives and preventive measures to avoid excavation damage against the number of third party damage incidents, and a comparison of damages as a function of the level of human or economic activity.

7.4.7 Plastic Pipe Failure Data

In-service plastic piping materials failure data are being collected by the AGA under the charter and oversight of the government-industry Plastic Pipe Database Committee (PPDC). However, data on instantaneous failures due to excavation damage to plastic pipe is not being collected by the PPDC and the CGA. Thus, data on the susceptibility to excavation damage of various plastic materials cannot be determined.

Furthermore, neither the existing nor the revised OPS incident report forms are designed to collect sufficient information to allow entry of incident data involving plastic pipe into the PPDC database.

7.5 Non-Technical Gaps

Many non-technical aspects unique to distribution such as impact on customers, operator-state relationships, interactions with local communities, and cost recovery exist and are an integral part of the gas delivery process. These have not been analyzed here, but could provide further insight into additional factors affecting the cost of gas and reliability of delivery as an added indicator of the degree of uniformity of natural gas distribution integrity practices, procedures and actions across the nation.

Further, individual state regulatory bodies have issued additional safety requirements if the local conditions warrant them, to help ensure the integrity of the distribution system in their particular state. Consideration of the specifics of such regulations was not within the scope of this study even though some input was gathered from the survey respondents.

8.0 MAJOR FINDINGS

The following are the major findings of this study:

8.1 Safety Performance

1. Over the study period 1990 through 2002, Serious Incidents, namely those involving a fatality or an injury show a statistically determined decreasing trend, with a decrease of approximately 40%.

2. Damage to the infrastructure by Outside Force was the leading cause of Serious Incidents during the study period. This category of incidents in the OPS database is responsible for 47% of the 601 Serious Incidents involving distribution facilities during the study period. The data show a statistically determined decreasing trend, with a decrease of approximately 50%.

3. Of the other incident cause categories in the OPS database, Corrosion caused only 6.5% of Serious Incidents; Construction/Operating Error and Accidentally Caused by Operator categories each accounted for 9.8% Serious Incidents.

4. The predominant component of outside force damage was third party damage, (typically excavation damage inflicted on distribution facilities by a third party not related to the gas system operator or its surrogate), contributing nearly 35% to the total number of serious incidents.

5. The proportion of third party damage incidents was the largest for polyethylene mains. Cast iron is subject to a higher proportion of incidents from earth movement, but contributing less than 5% to the total number of serious incidents.

6. For service lines, the proportion of third party damage incidents was the largest for polyethylene.

7. Throughout the analysis, the use of the serious incident statistics, as well as fatality and injury counts for safety performance analysis, is made more difficult by the presence of more than 27% of Serious Incidents in the non-descript categories entitled "Other" and "No Data" in the OPS database. Detailed specific features of individual data points in these two categories are not readily available in the database.

8. Of the 601 total Serious Incidents, 46% occurred on distribution mains, while 34% of the incidents occurred on service lines and meter sets combined. The remaining incidents were categorized by operators as "Other" or "No Data".

9. Normalized to 100,000 miles of main material, cast iron main showed more incidents than polyethylene main, which in turn showed more incidents than steel main. When only third party damage incidents are examined in the outside force category, polyethylene showed the highest average normalized incident rate for the study period, followed by cast iron and then steel.

10. Normalized to 100,000 miles of service material, incidents on polyethylene and steel services were essentially the same. When only third party damage incidents are examined in the outside force category, the average normalized incident rate for polyethylene service lines was higher than the normalized rate for steel service lines over the study period.

11. Fatality and injury counts closely follow the relative proportions shown by the serious incident data. This is true regardless of the approach used for analysis, whether by cause, by part of the system, or by material of construction. The only situation where this was not the case was in the "No Data" category where one incident accounted for 75 fatalities and injuries.

12. The Mann-Kendall (M-K) test was used to identify whether a statistically significant decreasing or increasing trend may exist for a given data set. No increasing trends were validated.
13. A number of gaps in the OPS data were identified that precludes a deeper insight into the mechanisms by which specific threats affect the integrity of distribution pipelines.

14. Distribution system gas leak information from the OPS annual report database could not be used as an indicator of the level of integrity of the nation's gas distribution system because the data collected may not be specific enough to be uniformly reported by operators and because the OPS database does not include a complete annual inventory of leaks or newly identified leaks during the reporting period.

15. Unaccounted for gas information in the OPS database could not be used as an indicator of the level of integrity, as the data typically contain a heavy proportion of accounting and measurement errors and do not provide reliable information on gas lost through leakage to the atmosphere.

16. Normalized by 100,000 miles over the study period, the average fatality and injury counts for gas distribution are essentially the same as the counts for gas transmission.

8.2 Regulations and Industry Practice Addressing Distribution

Based on an industry practices survey of a representative cross-section of gas distribution companies, the following significant findings were compiled:

1. Operators use additional prevention and mitigation measures that exceed the requirements of the federal pipeline safety code to address specific threats to the integrity of distribution pipelines. The measures used are generally consistent with the perceived significance of the threat as indicated in the industry practices survey results.

2. The top five processes identified by the survey group as having the highest impact on distribution integrity are: (1) cathodic protection systems; (2) leak surveys; (3) operator qualification programs; (4) one-call systems; and (5) planned pipe replacement programs. The programs and processes in this group are consistent with indications from the incident statistics.

3. Operators address the dominant threat of third party damage with prevention and mitigation measures that include those required meet code-mandated pipeline safety requirements and additional ones that exceed the code requirements.

4. Over 80% of the operators in the survey reported employing risk-ranking tools to evaluate their distribution infrastructure.

5. Over 65% of the companies that participated in this study have planned replacement programs for cast iron and almost 80% have such programs for bare steel.
6. Pipe replacement between 1990 and 2002 has reduced the amount of cast iron main mileage by 21% and the amount of bare, unprotected steel main mileage by 7%. During the same period, the number of bare, unprotected steel services has been reduced by 13%.

7. During the period covered by this study, the proportion of steel mains and services has decreased while the proportion of plastic mains in the system has increased by 39% and plastic services by 50%.

8. This study documented in Appendix O, recent initiatives and programs that have been put in place to help further address improvements in practices and procedures and identify areas where further changes may be needed. Assessing the effectiveness of such initiatives and programs was not part of the scope of this study.

9. From the operator responses received, there were no clearly visible gaps between specific threats to distribution integrity and the industry practices that address the threats.

10. The respondents to the survey did not identify any readily apparent gaps between the pipeline safety regulations and any of the threats to the distribution infrastructure.

8.3 Differences Between Transmission and Distribution Infrastructure

Key differences exist between transmission and distribution pipeline systems in the following areas:

- type of infrastructure;
- size of pipelines;
- system operating pressures;
- mix and types of materials of construction;
- typical failure mechanisms;
- inspection methods and inspection frequencies;
- gas odorization;
- location of facilities; and
- connection to customers.

Such differences help to further characterize the challenges faced by operators when addressing and ensuring the integrity of gas distribution systems.